Bulletin 151

Petroleum Technology 40

DEPARTMENT OF THE INTERIOR

FRANKLIN K. LANE, SECRETARY

BUREAU OF MINES

VAN. H. MANNING, DIRECTOR

RECOVERY OF GASOLINE FROM NATURAL GAS BY COMPRESSION AND REFRIGERATION

BY

W. P. DYKEMA

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CONTENTS.

TABLES.

ILLUSTRATIONS.

RECOVERY OF GASOLINE FROM NATURAL GAS BY COMPRESSION AND REFRIGERATION.

By W. P. Dykema.

INTRODUCTION.

In investigating the general problems that relate to the petroleum industry in the United States, the Bureau of Mines has given considerable attention to the recovery of motor fuel from natural gas. Recent developments in gasoline power units and their increasing use have made it imperative that all fractions of petroleum suitable for fuel in this type of engine be conserved. The bureau has issued a number of publications on this subject. Among these are Technical Paper 10, "Liquefield products of natural gas, their properties and uses"; Bulletin 42, "The sampling and examination of mine gases and natural gas"; Technical Paper 87, "Methods of testing natural gas for gasoline content"; Bulletin 120, "Extraction of gasoline from natural gas by the absorption method"; and Bulletin 88, "The condensation of gasoline from natural gas."

This report treats of the compression and refrigeration process for the recovery of gasoline from natural gas from the viewpoint of the practical engineer and business man. Conditions of actual operation and the equipment in use are cited and described so that operators, and others interested, can compare the variations in methods of treating natural gas for its gasoline content in the different fields and also the conditions encountered and the features that control the methods used.

ACKNOWLEDGMENTS.

The writer heartily acknowledges the valuable assistance and cooperation of the many plant operators and gasoline producers who have cheerfully furnished data on their plants and granted the privilege of plant inspection.

Particular thanks are due to Messrs. W. R. Hamilton, G. L. Goodwin, and D. L. Newton for the many courtesies extended the writer and for much of the information regarding cooling by expanded gas as practiced in the California fields.

Thanks are also due Messrs. W. P. Donovan, Thomas Chestnut, J. C. Gillespie, A. W. Peake, and R. E. Downing for valuable information on practices in the Mid-Continent fields.

HISTORY OF THE INDUSTRY.

The early history of the manufacture of natural-gas gasoline has been published by the Bureau of Mines [a] in previous papers on the subject. The present practice is the result of the advance developed by a study of the needs of the industry, by improvements in machinery and equipment, and by a better understanding of the thermodynamic and other physical principles involved. A very small proportion of the plants erected have been commercial failures, and most of those which have failed lacked capital to carry them over a period of low prices for gasoline. Many of these plants are still operating, the company having been reorganized or bought up by larger corporations, and under present market conditions they show satisfactory returns.

The following table shows the distribution of casing-head gasoline plants and the amount and value of the gasoline produced in the United States in 1915:

TABLE 1.—*Gasoline recovered from natural gas and sold in 1915.*[a]

State.	Number of plants.	Quantity.	Value.	Average recovery of gasoline per 1,000 cubic feet.
		Gallons.		*Gallons.*
Oklahoma	63	31,665,991	$2,361,029	3.60
California	20	12,835,126	975,397	1.60
West Virginia	114	[b]10,853,608	927,079	2.30
Pennsylvania	139	[b]5,898,597	569,873	2.73
Ohio	50	2,198,715	167,138	2.80
Illinois	16	1,035,204	80,049	2.29
Texas	1			
New York	4			
Louisiana	2	[b]877,424	70,258	1.32
Kansas	2			
Colorado	2			
Kentucky	1			
	414	65,364,665	5,150,823	2.57

[a] Northrop, J. D., Mineral Resources U. S. for 1915, U. S. Geol. Survey, 1916, p. 997.
[b] Includes gasoline resulting from natural condensation in gas mains.

In January, 1917, the number of plants in California had increased to 30, with an estimated daily production of more than 60,000 gallons, and the number of plants in Oklahoma to 95, with an estimated daily production of 200,000 gallons.

[a] Allen, I. C., and Burrell, G. A., Liquefied products from natural gas, their properties and uses: Tech. Paper 10, 1912, pp. 4–7; Burrell, G. A., The suitability of natural gas for making gasoline: Tech. Paper 57, 1913, p. 17; Burrell, G. A., Seibert, F. M., and Oberfell, G. G., The condensation of gasoline from natural gas: Bull. 88, 1915, pp. 9, 10; Burrell, G. A., Biddison, P. M., and Oberfell, G. G., Extraction of gasoline from natural gas by absorption methods: Bull. 120, 1917, pp. 11–14.

FACTORS TO BE CONSIDERED IN EXAMINING FIELD FROM WHICH GAS IS TO BE TAKEN.

Before a compression plant can be properly designed to treat natural gas from any given area, a thorough study of the history of the field in general and especially of the sand from which the gas is to be taken should be made, also complete testing to determine the volume and gasoline content of the gas from the area under consideration should be made. This precaution is particularly necessary for a field in which there are no plants in operation that can be studied and used as a precedent.

A knowledge of the history of the field is important in determining the probable life of the wells and the decline in volume of gas produced from year to year. A plant built in California to treat 2,000,000 cubic feet per day has been able to get only half that amount because of the decline in gas production from the wells after the initial rock pressure was relieved, and new wells drilled for oil on the same lease have not thus far brought the quantity of gas up to the plant capacity. Gas from adjoining leases could not be obtained for treatment, and the plant at the time of the writer's visit was running at half capacity, as stated.

In all gas and oil fields in the United States it is found that as the pressure in the wells decreases the gas becomes richer in gasoline content. It is doubtful, however, if the actual total quantity of gasoline vapor from a given well increases, but it seems to be a fact that the amount of gasoline vapors produced declines much less rapidly than either the oil or gas production from a given well or area. This has been found to be practically true of West Virginia and California wells as long as the wells produce oil either under rock pressure or vacuum. In Pennsylvania a small compression plant is treating gas from wells that have long ceased to produce oil and are pumping salt water under vacuums of 26 inches of mercury.

New oil wells producing many million feet of gas under high rock pressure, such as are often brought in, in the Mid-Continent and California fields, are not considered, because gas produced under these conditions of pressure and volume practically never finds its way to compression plants. The gas produced under rock pressures of 400 to 1,500 pounds per square inch contains only comparatively small proportions of the heavier gasoline fractions and comparatively large quantities of the lighter or "wild" fractions, as would be expected from the condition under which the gas is held while in contact with the oil from which it must receive its charge of condensable vapors.

CHARACTER OF THE SAND.

A knowledge of the sand from which the gas is to be produced is a valuable factor in designing a plant; the thickness, texture, or degree of cementation bear directly on the future of the field as a

gas and gasoline producer. Thick sand of close texture indicates long life as an oil producer, and consequently a long life for gasoline production. Loose, uncemented sands, such as are found in California, will not withstand the suction of vacuum pumps, which causes the sand to come in and stop or injure the pumps. This inflow of sand reduces the production of oil and increases the expense of cleaning the wells, so that companies treating their own gas do not permit the vacuums held on walls to exceed 1 to 2 inches of mercury at the casing head. This limitation of vacuums may react in such a way as to make compression plants unprofitable when the oil production has become small and the rock pressure has been completely relieved.

CHARACTER OF THE OIL.

Casing-head gas produced with high-gravity oil is almost universally rich in gasoline vapors, except when the gas is produced under extremely high pressures. However, the fact that an oil is of low gravity can not always be depended on to indicate small gasoline content, as has been shown by compression practice in California. As a rule, in California, casing-head gas produced with oil having a gravity of less than 22° B. does not yield enough gasoline for profitable compression. However, in the Salt Lake field, the oil has a gravity of 15° to 17° B. and still the casing-head gas is commercially valuable for its gasoline content. Analyses by the Bureau of Mines[a] of oil from this field shows that it carries exceptionally high proportions of asphaltum (55.3 per cent), but also carries lighter products, ranging up to fractions distilling over at 150° to 200° C., to which are due the gasoline vapors in the gas. The Kern River field, yielding oil with an average gravity of 14° B. has not, so far, produced any gas that is being treated for gasoline.

WATER SUPPLY.

Water being essential in all plants making gasoline by compression methods, the supply and the quality of water available should be carefully determined. The cooling coils and the compressor jackets of a plant treating 1,000,000 cubic feet of gas daily at a pressure of 250 pounds per square inch will use 100 to 300 barrels of water a day, depending on the design of the water-cooling system and the temperatures obtained. The loss is accounted for by the evaporation and, in plants where towers or sprays over ponds are used, by water being carried away by the wind. In the oil fields much of the water is so heavily charged with mineral salts as to be almost useless for boilers, gas-engine jackets, and compressor jackets. Such water to be made fit for boiler use must be treated with a so-called "boiler

[a] Allen, I. C., Crossfield, A. S., Jacobs, W. A., and Matthews, R. R., Physical and chemical properties of the petroleums of California: Tech. Paper 74, Bureau of Mines, 1914, p. 13.

compound." For cooling jackets of machines the water must be condensed, otherwise it forms a scale, which interrupts the circulation of water and is dangerous both to machinery and to the operators, and also cuts down the efficiency of the engine and compressor by permitting overheating of the cylinders and of the gas being treated.

TRANSPORTATION FACILITIES.

The matter of transportation is of importance, as on it depends, in part, the questions of blending, size and weight of units, plant location, and length of pipe lines. Before a plant is designed, the most economical product should be determined, as it may be that producing the maximum quantity of condensate possible from a given gas will be as profitable as a smaller quantity of a less volatile product. Producing the maximum quantity of condensate from a gas requires high pressures and blending with naphtha as soon as possible after the condensate is precipitated. This requires machines to produce the high pressure, which adds to the cost of installation, and a continual supply of naphtha for blending. If the cost of freight on the naphtha coming to the plant and on the percentage of naphtha in the blended product going back to market, plus the cost of mixing and of losses in blending and handling, is greater than the value of the condensate produced in excess of the quantity that could be produced at a lower pressure without blending, it would be more profitable to produce less condensate of lower vapor tension capable of being shipped as made. For example, a plant in the Mid-Continent field, situated an excessive distance from the nearest refinery from which it could obtain naphtha for blending, finds that using a pressure of 80 pounds from single-stage compressors, and producing 1.8 gallons of condensate with a gravity of 75° to 80° B. and a vapor tension of 5 to 6 pounds, is more profitable than producing 3 gallons of condensate having a gravity of 94° to 98° B. and blending it at or near the plant.

The distance from a railroad will also have a bearing on the cost of erecting a plant. Pipe lines are usually built from the plants to loading racks or blending stations on the railroad. More recent practice seems to favor blending at the compression plant, which necessitates pumping the naphtha to the plant and pumping the blended product back to the loading station through pipe lines. The greatest expense from being at a distance from a railroad, however, is that of hauling equipment and repairs. Machines built in parts too large to handle on the wagons or trucks usually found in oil fields are much more expensive to place than machines shipped in smaller parts. Roads, distances, and the weights of large parts of machines should be considered when a plant is being designed or an estimate of cost figured.

Plate I, *A* (p. 24), shows two single castings weighing 31,000 pounds each, which were placed in a plant that could be reached only by narrow, steep roads. The trouble and expense of hauling such parts is a factor in plant construction.

The general topography at one compression plant is shown in Plate II, *A* (p. 24).

DISTRIBUTION OF WELLS.

If the wells from which gas is to be taken are distributed over a wide area, it is well to consider the construction of two or more smaller plants rather than one larger plant. One plant visited by the writer treats gas collected over an area of approximately 32 square miles. The extensive pipe-line system required to bring the gas to the plant and return it to the various leases, with the booster stations and equipment necessary to maintain them, makes this plant, in the opinion of the management, more expensive and less efficient than two or three smaller plants would have been.

CONDITION OF WELLS.

Before erecting a compression plant in an old field the condition of the casings in the wells from which gas is to be taken should be ascertained. In an old field in Pennsylvania it was found that the casings were badly rusted and allowed excessive quantities of air to enter the lines as soon as a vacuum of more than 1 or 2 inches was placed on them. The wells made an average production of only 1,000 cubic feet of gas a day, so that the expense of recasing would not seem to be warranted.

J. O. Lewis, petroleum technologist of the Bureau of Mines, states that air is often admitted to wells in which the casing has not been properly placed, the air entering through porous strata from other wells which are not being held under vacuums.

TESTING NATURAL GAS.

The testing, measuring, and sampling of natural gas for its gasoline content has been described in Bureau of Mines publications[a] by G. A. Burrell and his associates, and will only be taken up briefly by the writer.

Many compression plants are successfully treating gas about which few facts were known before the plant was erected. Much time and expense could have been saved, however, if more had been learned of the physical and chemical characteristics of the gas before the plans

[a] Burrell, G. A., and Jones, G. W., Methods of testing natural gas for gasoline content: Tech. Paper 87, 1916, 23 pp. Burrell, G. A., Seibert, F. M., and Robertson, I. W.: Analysis of natural gas and illuminating gas by fractional distillation at low temperatures and pressures: Tech. Paper 104, 1915, 41 pp. Burrell, G. A., Seibert, F. M., and Oberfell, G. G., The condensation of gasoline from natural gas: Bull. 88, 1915, 106 pp.

of the plant were made and the machinery installed. The investment in a compression plant is large enough to warrant the expense of having all necessary tests, analyses, and measurements of gas made and checked before the plans and details of construction are taken up.

SPECIFIC GRAVITY TEST.

Natural gas having a specific gravity of 0.78 (air = 1) and higher is being successfully treated in compression plants. The specific gravity test is useful as an indicator, but the possibility of misleading variations through the presence of other gases, such as air, carbon dioxide, nitrogen and sulphur compounds, in the sample makes this test unreliable if used alone. If an analysis is made of the gas and the specific gravity of the hydrocarbon contents computed, the results are more dependable, but even then are not reliable enough to be used as a basis for final decisions regarding plant construction.

SOLUBILITY TEST.

The solubility test described by Burrell and Jones[a] is useful as an arbitrary test, because it is known that gases of a solubility of less than 30 per cent have not been successfully treated in compression plants.

In regard to the following table they state that "in all cases the yield represents the actual amount of gasoline sold after weathering."

Yield of gasoline from casing-head natural gas by compression method, corresponding to absorption and specific-gravity tests.[a]

Absorption by oil.	Specific gravity (air=1).	Yield of gasoline, gallons per 1,000 cubic feet of gas.	Absorption by oil.	Specific gravity (air=1).	Yield of gasoline, gallons per 1,000 cubic feet of gas.
Per cent.			*Per cent.*		
16	0.64	None.	50	1.29	3.00
23	0.83	1.00	48	1.37	3.50
30	0.90	1.75	44	1.38	3.50
37	1.00	2.00	65	1.38	4.00
39	1.03	2.50	84	1.41	4.50
38	1.07	3.00	86	1.46	5.00
54	1.21	3.50			

[a] Burrell, G. A., and Jones, G. W., work cited, p. 10.

It should be stated that both the specific-gravity test and the oil-absorption test fail when applied to residual gas from a gasoline plant because, although the results obtained will indicate high specific gravity and oil absorption, principally because of the presence of large percentages of the hydrocarbon gases, ethane and propane, yet the plant will have extracted the vapors of the liquid paraffins that constitute gasoline.

[a] Burrell, G. A., and Jones, G. W., Methods of testing natural gas for gasoline content: Tech. Paper 87, Bureau of Mines, 1916, pp. 7-10.

FRACTIONAL DISTILLATION.

The Bureau of Mines [a] has developed a technical laboratory test based on a method of freezing out the propane and higher hydrocarbon fractions, which accurately determines the percentage of condensable hydrocarbons, including propane and all other higher members of the hydrocarbon series. This test can be made only in a well-equipped laboratory by experienced gas analysts.

Another method, based on the principle of low temperatures, that was originated by the Smith Emery Co., of Los Angeles, Cal., is essentially as follows: Gas from the casing-head of the well is led through a service meter (see fig. 1) under a pressure of 12 inches of water (devised so as to blow out if that pressure is exceeded) to a copper tube three-fourths of an inch in diameter and 15 feet long, coiled so as to fit into an asbestos insulated container 18 inches deep and 12 inches square. The container is filled with acetone (product of wood distillation) to within 2 or 3 inches of the top. Carbon dioxide snow from steel bottles of carbon dioxide in the liquid state is added to the acetone until a saturated solution is obtained. Complete saturation of the solution is shown when a portion of the snow remains, as snow, on the bottom of the container. The temperature of the acetone is held constant at 70° F. below zero by the carbon dioxide used in this way. Gas is passed through the copper coil, submerged in the acetone bath, until 500 or 1,000 cubic feet, as shown by the meter, has been treated; the coil is then drained into a flask, the quantity of condensate measured, and the gravity tested. If the condensate obtained in this manner is higher in gravity and vapor tension than would be desirable as a plant product, the condensate can be weathered down to the desired product, thus indicating the quantity of condensate of desired gravity which the gas contains. One series of tests made in this manner produced a condensate having a gravity of 90° B., and an absorption plant treating the gas reports a production approximately equal to the results obtained in the original tests of the gas. It requires 2 or 3 bottles of carbon dioxide to conduct this method of testing for one day, and the gas from 6 to 10 wells can be tested in that length of time.

PORTABLE COMPRESSOR TEST.

It has become the practice, in testing natural gas for its gasoline content to determine its suitability for use in a compression plant, to make actual physical tests with a small portable plant consisting of a compressor, meter, and cooling coils mounted on a wagon or

[a] Burrell, G. A., Seibert, F. M., and Robertson, I. W., Analysis of natural gas and illuminating gas by fractional distillation in a vacuum at low temperatures and pressures: Tech. Paper 104, Bureau of Mines, 1915, 41 pp.

truck. Each well is tested by moving the compressor outfit to a point where gas can be taken from the casing head or from the gas line leading from the well. The reason for testing each well separately is that even in the same field gas from different wells has widely varying contents of gasoline vapor, and if comparatively dry gas is mixed with gas of greater vapor content, the yield of condensate will be decreased or greater pressure and a lower temperature will be required to precipitate an equal quantity. This point was proved in practice by a plant in California, which, by turning out of its lines the gas from a well making about one-half million cubic feet per day, increased the plant production, no change being made in the pressure or the cooling system.

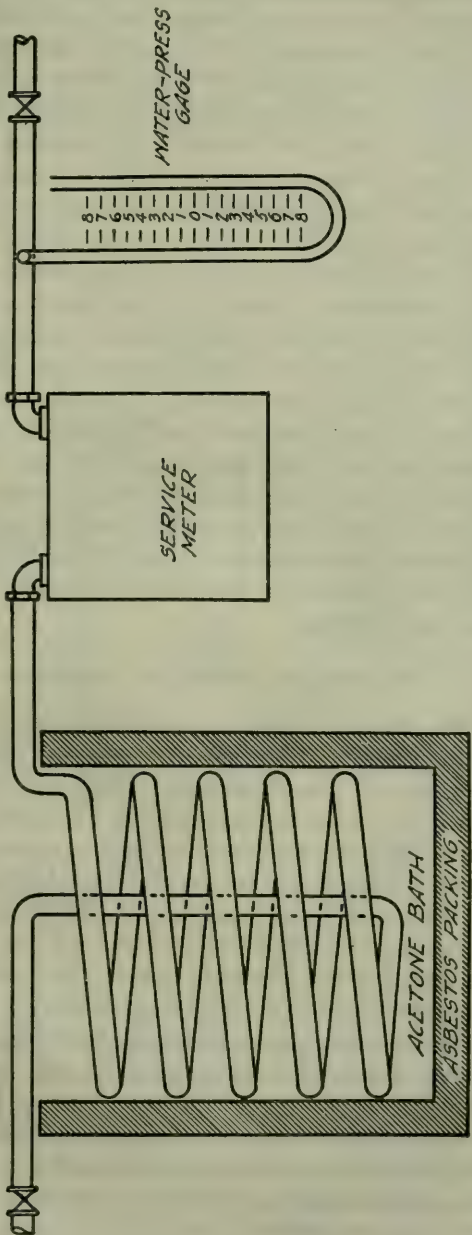

FIGURE 1.—Apparatus for testing natural gas by the acetone and carbon-dioxide method.

A portable testing outfit observed in operation by the writer consisted of a tank 12 by 36 inches used as a gas receiver, a 4-horsepower gas engine belted to a 3 by $3\frac{1}{2}$ inch single-acting compressor with a capacity of 3 cubic feet per minute, a single coil of 1-inch pipe of the continuous, return-bend type cooled by submerging in a wooden trough of water and ice, and a double coil, 12 feet long, of 1-inch pipe inside a 2-inch pipe, cooled by expanding the compressed gas through a valve connection between the outside and inside pipes.

The gas was brought from the well line through a ½-inch pipe fitted with a water gage for regulating the pressure on the intake receiver; this receiver also served as a trap for heavy oil and dirt. From the receiver the gas was compressed and delivered to the water-cooled coil at a pressure of 250 pounds, the water being cooled with ice. Ice was used because it gave lower and easily regulated temperatures, was more convenient to obtain than a large or continuous supply of fresh cold water, and permitted tests to be run at nearly the same temperature and under more uniform conditions. The gas from the water-cooled coil discharged into the chamber between the outer and the inner pipe of the double coil. At the discharge end of the outer or 2-inch pipe was suspended a 1-inch drip pipe to collect the condensate. Gas from the 2-inch pipe was expanded through the valve into the inner pipe to refrigerate the high-pressure gas flowing through the outside pipe and discharged through a service meter to the atmosphere. Records were kept of temperatures, pressures, and amounts and gravity of condensate produced. The tests were made at night to aid cooling. From time to time specific-gravity tests of gas from individual wells were made and recorded. When the gas from any well dropped noticeably in gravity, a compression test was run on it, and, if found too low in gasoline content for profitable recovery, was turned into the fuel lines of the lease and was not treated.

SOURCES OF ERROR IN PORTABLE COMPRESSOR TESTS.

The greatest source of error in making tests with portable outfits is the meters. Service or domestic meters become inaccurate if operated at pressures above those for which they were made, and should be tested before use even at normal pressures, and during use should be protected from excessive pressures by a water or mercury pressure gage placed on the pipe ahead of the meter intake. Pressures of 8 to 12 inches of water are usually used with meters of this type. Some operators use two meters, one on the intake and one on the discharge of the portable tester, the indicated amounts of gas being averaged in calculating the production.

Results are apt to be misleading when gas being treated in the testing machine is not cooled to the same temperature as under plant conditions or compressed to the pressure used in the plant. Small portable testing compressors can be adjusted and operated under conditions so nearly simulating actual plant conditions as to give reliable data on which to base estimates of pressures, temperatures, and recovery.

MEASURING THE FLOW OF NATURAL GAS.

The following description of the orifice-meter method of gas measurement is from Technical Paper 87[a] of the Bureau of Mines:

ORIFICE METER.

An instrument known as the orifice meter, for testing small flows of natural gas, is shown in figure 2. This instrument is simple in construction, consisting of a short 2-inch nipple, *b*, with pipe thread on one end and a thin plate disk on the other. The disk carried a 1-inch orifice, *a*, and a hose connection, *c*, for taking the pressure. The meter is especially intended for testing small gas wells and "casing-head" gas from oil wells. As a rule the flow of gas from an oil well is rather small, and it is not advisable to test the flow with a Pitot tube such as is used in testing large gas wells. In using the orifice tester it is necessary to know the specific gravity of the gas in order to obtain the flow.

Before the orifice well tester is attached to the casing head the well should be permitted to blow into the atmosphere until the head of the gas is reduced and the flow has become normal. Then the tester is attached by simply screwing it into the end of a 3-foot length of 2-inch pipe and the pressure is read in inches of water on the siphon gage, *d*. In the table[b] the flow of the well, with values for gas of different gravities, is opposite the gage reading. The orifice in the instrument should be kept dry and uninjured; otherwise the gage reading will not be correct.

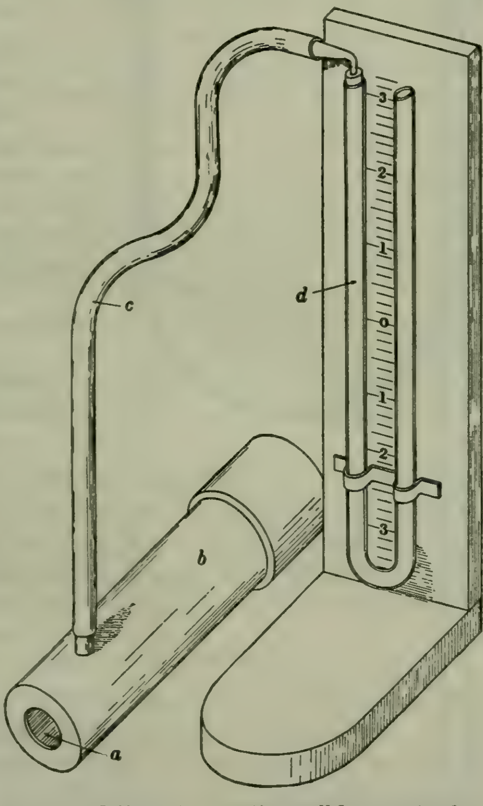

FIGURE 2.—Orifice meter for testing small flows of natural gas.

Beside the thin 1-inch orifice plate described above, orifice meters of this type are equipped with plates of the same thickness ($\frac{1}{8}$ inch) and with orifices of $\frac{3}{8}$, $\frac{1}{2}$, $\frac{3}{4}$, and $1\frac{1}{4}$ inch diameters for measuring flows of greater or less volume, and for checking, by two or more tests, the flow from the same well at different pressures. Figure 3 shows the design of meters in which are used a number of different sized orifice plates. The brass disks containing the orifices are carefully machined to a thickness of $\frac{1}{8}$ inch and are made to fit perfectly

[a] Burrell, G. A., and Jones, G. W., Methods of testing natural gas for gasoline content: Bureau of Mines, 1916, pp. 18-20.
[b] See Table 15, p. 115.

between the cap which holds the disk in place and the end of the 2-inch pipe. The orifice in the disk is accurately drilled to size, the edges being made square and not beveled.

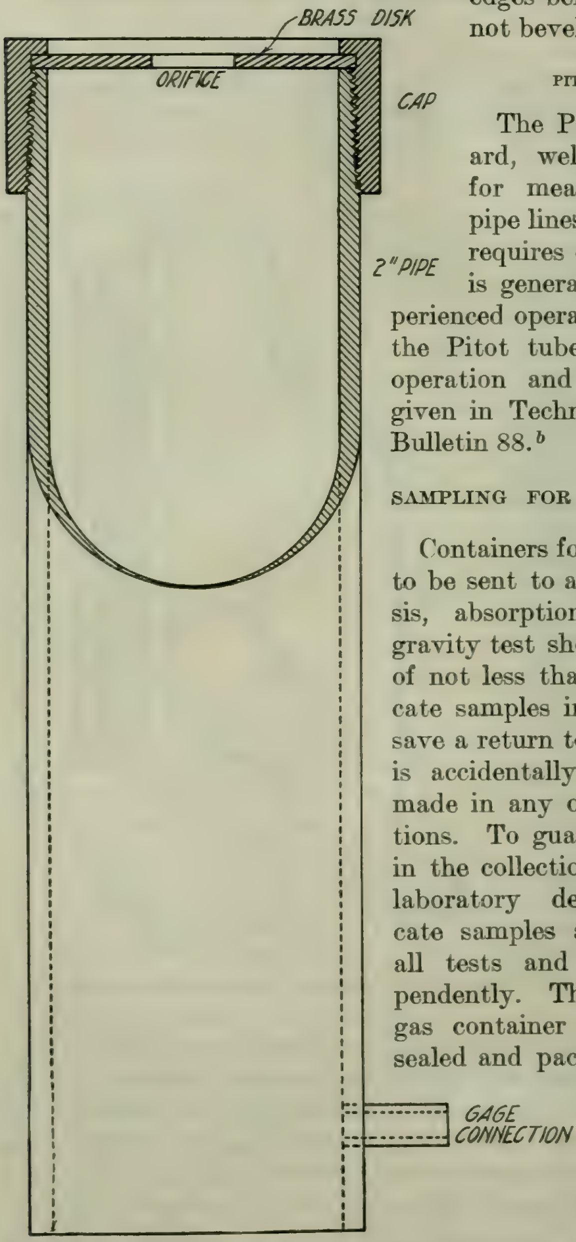

FIGURE 3.—Orifice meter in which different sized orifice plates may be used.

PITOT-TUBE METHOD.

The Pitot tube is a standard, well-known instrument for measuring gas flows in pipe lines and at gas wells; it requires careful attention and is generally used only by experienced operators. Descriptions of the Pitot tube and its method of operation and tables of flow are given in Technical Paper 87 [a] and Bulletin 88. [b]

SAMPLING FOR LABORATORY TESTS.

Containers for natural-gas samples to be sent to a laboratory for analysis, absorption test, and specific gravity test should have a capacity of not less than 1 pint, and duplicate samples in two containers may save a return to the field if a sample is accidentally lost or an error is made in any one of the determinations. To guard against errors both in the collection of samples and in laboratory determinations, duplicate samples are often taken and all tests and analyses run independently. The bottle or other gas container should be carefully sealed and packed to avoid leakage from poor stoppers and expansion and contraction of the gas from wide changes in temperature.

[a] Burrell, G. A., and Jones, G. W., Methods of testing natural gas for gasoline content: Bureau of Mines, 1916, pp. 21–24.

[b] Burrell, G. A., Seibert, F. M., and Oberfell, G. G., The condensation of gasoline from natural gas: Bureau of Mines, 1915, pp. 37–45.

COLLECTING A SAMPLE BY AIR DISPLACEMENT.

Filling a bottle or other container by air displacement is a rapid and convenient method, often used in the field. A small hose is placed over a pet cock in the gas line, the other end being inserted inside of the container. A gentle stream of gas is then allowed to flow into the container for four or five minutes, displacing the air. If the gas is known to be lighter than air it is best to invert the bottle, thus allowing the light gas to displace the heavier air; if the gas is heavier than air, the reverse method is preferable. The bottle is then quickly corked, and sealed by covering the stopper with a coating of warm paraffin. The difficulty with this method is the uncertainty whether all of the air has been displaced by the gas.

COLLECTING A SAMPLE BY WATER OR MERCURY DISPLACEMENT.

A more accurate method of obtaining a gas sample is by the displacement of water. In this method the bottle is filled with water and inverted beneath the surface of water in a bucket or other convenient receptacle, the hose from the gas line is allowed to discharge below the mouth of the inverted bottle until the water in it has been entirely displaced by the gas. The bottle is then closed or corked while still beneath the surface, and after drying and sealing with paraffin, can be transported without danger of contamination of the contents.

Mercury may be used in the same manner as water, but requires that considerable volumes of this liquid be kept with the sampling apparatus, which adds to its bulk and weight. Displacement of mercury is, however, the most accurate method of filling a container with the gas to be tested, and insures the least possible contamination.

SAMPLING AND TESTING IN GENERAL.

All tests, measurements, and determinations of natural gas to be used for gasoline manufacture should be checked and proved. Duplicate tests, analyses, and measurements should be made by different persons, if possible. If the duplicate results show variations large enough to be of importance in determining plant capacity, methods, or equipment, a third test should be carried out to determine which results can be trusted and can be used in plant design. Too much importance can not be placed on accurate testing and measuring of gas to be treated for gasoline content, for although during the treatment in a commercial plant many problems arise that can not be foretold, many characteristics of the gas can be determined which have a direct bearing on the pressures and temperatures necessary and the gravity and vapor tension of the condensates produced.

METHODS OF NATURAL-GAS GASOLINE MANUFACTURE.

Plants treating natural gas for its gasoline content fall under one of three mechanical and physical subdivisions—compression, refrigeration, and absorption, or a combination of these methods. Each division varies widely in mechanical details of both equipment and operation. Gasoline recovery by compression and refrigeration will be discussed in the following pages. Recovery by absorption methods has been described in Bulletin 120.[a]

THEORY OF PRECIPITATION.

CONDENSATION BY COOLING.

The theory of the precipitation of vapors from natural gas is in a way comparable to that of the precipitation of water vapor from the atmosphere. Water vapor is known to exist in the air at all times in varying proportions, but is invisible unless condensed by cooling. Cooling to a temperature below that at which the air is saturated with the water vapor it contains causes precipitation in the form of snow, hail, frost, rain, fog, or dew. This fact is also illustrated by beads of water collecting on the outside of a pitcher of ice water, and by the formation of frost on the refrigeration pipes of expansion units, as shown in Plates V, *C*, VI, and VII (pp. 34 and 36). The air coming in contact with the cold surface of the pitcher or pipes is cooled below its dew point and the moisture which it can no longer hold as vapor condenses as water or frost on the surface. By further cooling of the air more moisture would be condensed, and if cooling were carried far enough practically all of the water vapor could be precipitated without the aid of pressures higher than atmospheric.

CONDENSATION BY COMPRESSION.

In plants compressing air it is found that air, after having been made more dense by increase of the pressure and decrease of the volume, deposits moisture at atmospheric temperature, and as the pressure is increased larger percentages of the contained water vapor are precipitated. Hence either high pressures or low temperatures increase the condensation of the water vapor.

In the exceedingly dry atmosphere of the Arizona and Nevada deserts, operating air compressors at a pressure of 100 pounds and cooling the compressed air only to atmospheric temperature always causes precipitation of water, and of lubricating oils from the cylinders, in the air receiver. That all of the moisture in the air is not deposited in the receiver is shown by the fact that in pumps driven by compressed air some moisture freezes in the cylinders and also forms frost on the exhaust outlet.

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[a] Burrell, G. A., Biddison, P. M., and Oberfell, G. G., Extraction of gasoline from natural gas by absorption methods: Bull. 120, Bureau of Mines, 1917, 71 pp.

The condensable fractions in natural gas, like those in air, are not visible under ordinary conditions, but at times the sudden release into the atmosphere of gas from confinement under pressure will cause vapors of hydrocarbons to form a mist resembling fog or steam.

In the treatment of natural gas for gasoline recovery the result desired could be accomplished either by compression or refrigeration, but the complex mixture of gases and vapors complicates the problem. Without an exact knowledge of the various members and the proportion of each to the whole, an attempt to calculate the most suitable pressures and temperatures becomes little better than a guess, and the most practical solution is by tests and experiments. According to the law of partial pressures,[a] if gas contains 10 per cent of condensable vapor and is under a pressure of 200 pounds, the condensable 10 per cent has acting upon it a partial pressure of 20 pounds, or 10 per cent of the total pressure. As the proportion of different condensable vapors in the gas becomes smaller through their partial condensation, the partial pressure acting on them also becomes less. The percentage of the gage pressure acting on any one of the gas or vapor constituents varies in proportion to the percentage of volume occupied by that constituent. If the constituent is condensable, condensation will lower its proportion to the volume of uncondensed gas to a point at which the partial pressure acting on it is too small to cause further condensation, leaving a portion of the vapor uncondensed throughout the entire treatment. As the acting pressure becomes lower, condensation tends to cease, but lowering the temperature will cause further condensation. Under constant gage pressures and decreasing temperatures, the largest percentage of the heavier hydrocarbons contained in the gas is recovered, and the losses are confined to the lighter members.

Although all of the condensable vapor and even the true gases can be liquefied by increasing the pressure or reducing the temperature sufficiently, the application of these processes in treating natural gas for gasoline is limited by the commercial considerations. Extremes of either pressure or temperature would yield condensates too volatile for commercial use, also the machinery and other equipment required would be expensive to install and difficult to operate and maintain.

To recover the valuable hydrocarbon fractions that are held as vapors in natural gas, only such pressures and temperatures are necessary as can be obtained by the use of machines and fittings of standard construction and capacities. As the power used to compress the gas heats it, developing power by expanding the compressed gas cools it. By using the cooled gas as a refrigerant, the

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[a] Lucke, C. E., Engineering thermodynamics, 1912, p. 481.

temperature necessary, in conjunction with the pressures obtained, to extract the maximum of commercial condensate can be developed.

The temperature and the pressure that will yield the most profitable results are those that together will recover the largest possible amount of condensates of low vapor tensions and as much of the lighter parts as can be so blended or handled as to conform with legal standards of safety and make a good motor fuel

ABSORPTION THEORY.

The absorption process for recovering condensate from natural gas is based on an entirely different physical property, that of the solubility of vapors in liquids. In this process the gas is brought into intimate contact with a liquid which dissolves or absorbs the vapors; these vapors are later distilled from the absorbing medium and condensed.

USE OF COMBINATION COMPRESSION AND REFRIGERATION PROCESS.

As shown above, the fundamental principles of the compression process are compression and cooling of the natural gas to pressures and temperatures at which certain hydrocarbons condense.

Plants of this character are erected to treat casing-head gas from oil sands or from sands closely associated with oil, the gas being brought to the surface either between the casing and tubing of an oil well or with the oil in the tubing. The quantity of gas from each well is usually comparatively small and in some installations as many as 500 or 600 wells are connected with one compression plant of not more than the average capacity.

The dry (treated) gas is, at most plants, used on the oil leases to drive the gas engines of the compression plant, and also for gas and steam engines in pumping and drilling wells. A few compression plants sell the treated gas for commercial use in cities or for manufacturing purposes. The cost of pipe lines and equipment necessary to deliver the small quantities of gas to market would, in general, be excessive. There is seldom much gas left after the quantity necessary for furnishing power has been used.

The value of the gas for heating, power, and lighting is not impaired appreciably by removing the gasoline content. If this gas were not treated, the gasoline would, at most leases, be burned with the gas used for power purposes and practically be wasted as far as serving any useful purpose is concerned.

GAS LEASES.

Until 1914 practically all the gas being treated for its gasoline content was sold or leased under varying conditions to gasoline producing and marketing companies independent of the companies pro-

ducing the oil. Since that time the oil producing companies, realizing the profits to be made, have constructed compression plants to treat the gas produced with the oil on their leases, and in many instances are now purchasers or lessors of gas from surrounding properties.

Before 1914 gas leases were made mostly on a flat rate, which varied from 2 to 5 cents per 1,000 cubic feet. Often the contract stipulated the vacuum to be held on the oil wells, and specified that any treated gas not used to run the compression plant was to be returned to the lease from which it was taken, the return gas lines to be paid for and laid by the purchasing party. Other leases required that a certain percentage of the gas delivered to the compression plant should be returned, this figure in some instances being as high as 80 per cent.

SLIDING-SCALE LEASE.

One lease in Pennsylvania required that 7 cents per 1,000 cubic feet of gas be paid the lessor when the price received by the lessee for gasoline in tank car lots during the preceding month averaged 10 cents per gallon or less, and an advance of 1 cent per 1,000 cubic feet for each advance of 2 cents in the monthly average price of gasoline. The gasoline company had made arrangements to sell the treated gas at 12 cents per 1,000 feet to a company which supplies gas to near-by towns. This was one of the few plants found by the writer that made such disposal of the dry gas.

Such a form of contract, known as the sliding-scale lease, is being used almost entirely at present in the Mid-Continent fields, except that usually the contract stipulates that gas after treatment shall be returned to the lease from which it was originally taken. It also provides that all gas necessary for power to operate gas and water pumps as well as the compressor plant, shall be taken from the treated-gas lines at no cost to the lessor.

At the present time (December, 1916) leases in Oklahoma are being made on what is known as the 4-10 or the 5-10 basis, meaning that the price paid for the privilege of removing and selling the gasoline from the gas is to be 4 cents or 5 cents per 1,000 cubic feet when the price received for the product is 10 cents per gallon, with an increase of 1 cent per 1,000 feet of gas for each additional 2 cents per gallon, as in the Pennsylvania lease previously mentioned. On the 4-10 scale, with gasoline selling at 18 cents per gallon f. o. b. the plant, the price paid for gas would be 8 cents per 1,000 feet.

WEAK POINTS OF LEASE.

There seems to be two very weak points in such a form of contract; one is that no account is taken of the present or future quan-

tity of condensate in the gas, and the other is that as the wells and field grow older the percentage of gas returned to the original owner will become progressively less and eventually will become nil. In the Glenn pool, Oklahoma, this point has been reached at some plants.

In one plant, to the knowledge of the writer, the volume of treated gas discharged is at times insufficient to furnish fuel for the engines running the pumps and compressors. This condition is quite usual in older districts such as Sistersville, W. Va., where dry gas is bought to operate the compression plants, or, as at one plant, electric power is purchased and is used to drive the compressors.

As the quantity of gas decreases, the owner will receive less for the gas and have less treated gas returned to him, being forced eventually to buy gas for lease power while the plant operator will, for a long time at least, make the same or a slightly decreased quantity of marketable condensate. It would seem that these conditions should be taken into account in the gas contract.

ROYALTY LEASES.

Royalty leases are made and held in some fields, particularly in California, but do not seem to have been generally used throughout the United States.

Before the compression process and its results became well known and understood, gas could commonly be obtained on a royalty of one-eighth of the value of the product marketed, but as the gas producers learned of the treatment and profits, royalties have increased. In California, as much as one-third of the value of the product for gas containing less than 2 gallons of gasoline per 1,000 cubic feet is being paid. The writer is reliably informed of a contract in Oklahoma under which a royalty of one-half is being paid, the gas producing between 4 and 5 gallons of gasoline per 1,000 cubic feet.

FACTORS CONTROLLING ROYALTIES AND LEASES.

The royalties and prices that can be paid for gas under lease for gasoline recovery depend on the following conditions:

Wells scattered over a wide area will necessitate an expensive gathering system, including pipe lines and pumps or booster stations, and the cost of operation and upkeep. The quantity of condensate in the gas is vital because the cost of a plant and of plant operation is practically the same for rich or lean gas. If the gas is to be returned to the original owner for use on the lease, the cost, upkeep, and operation of the return or "dry gas" line are to be considered. The distance from a railroad station and the length of pipe lines required to bring the blending naphtha to the plant and transport the product to the station, also the distance from a market, and the source of naphtha supply will have a bearing on production and marketing costs.

The time the lease or contract is to run is also a factor which directly affects the price that is to be paid for gas, as the total cost of installation must be paid out of net receipts by the time the contract expires.

In general, all the factors entering into any manufacturing enterprise must be taken into consideration when the price to be paid for gas leases or royalties is being set.

METHODS OF COLLECTING NATURAL GAS.

The term "casing-head gas," when strictly applied, means gas coming from an oil sand between the casing and the tubing through which the oil is pumped. This term, however, as used in connection with compression plants, has been broadened so as to apply to any gas rising with oil in the tubing, or from flow lines, and to vapors coming from oil in traps or flow tanks.

In eastern practice it is usual to collect only the gas coming up between the casing and tubing in wells which are usually held under high (20 to 26 inches of mercury) vacuums, no attempt being made to collect the gas coming up with the oil in the tubing or the light fractions given off in flow or storage tanks. Oklahoma operators collect gas at the casing head, and in some instances from flow lines and flow tanks. In California an entirely different practice has developed, because of the soft running oil sand in most California fields. The oil and gas from one or more pumping or flowing wells is led into a specially built tank, called a trap. Traps of different designs are so constructed and operated as to permit the separation of the oil and the gas at pressures either above or below atmospheric, as circumstances may require.

USE OF TRAPS.

Originally traps were invented and designed to work under pressure with the object in view of separating, collecting, and saving the gas and also the oil atomized and mechanically carried with the gas into pipe lines or into the atmosphere; also to hold in the oil the gasoline fractions that would otherwise be volatilized when the pressure on the oil was released; and, further, to allow the oil to absorb as much of the condensable fractions from the gas as possible, thus raising the gravity of the oil and in a measure saving the most desirable fractions of the crude product. As an instance of the use of a trap and its effect on the oil produced, F. B. Tough, of the Bureau of Mines, cites the use of one at a gusher in the Midway, California, field. This well when flowing through a trap produced oil having a gravity of 32.5° B., and when flowing uncontrolled under considerable rock pressure into a collecting sump produced oil, as collected in the sump, with a gravity of 26° B., a gain of over 6° B. resulting from the use of the trap.

Traps are of interest to the casing-head industry principally as separators of oil and gas, or, as developed and used by at least one company, for holding a vacuum on the oil to separate from it such fractions as will distill off at the normal temperature and under a vacuum of 5 to 15 inches of mercury, thus reversing the usual effect and method of trap operation.

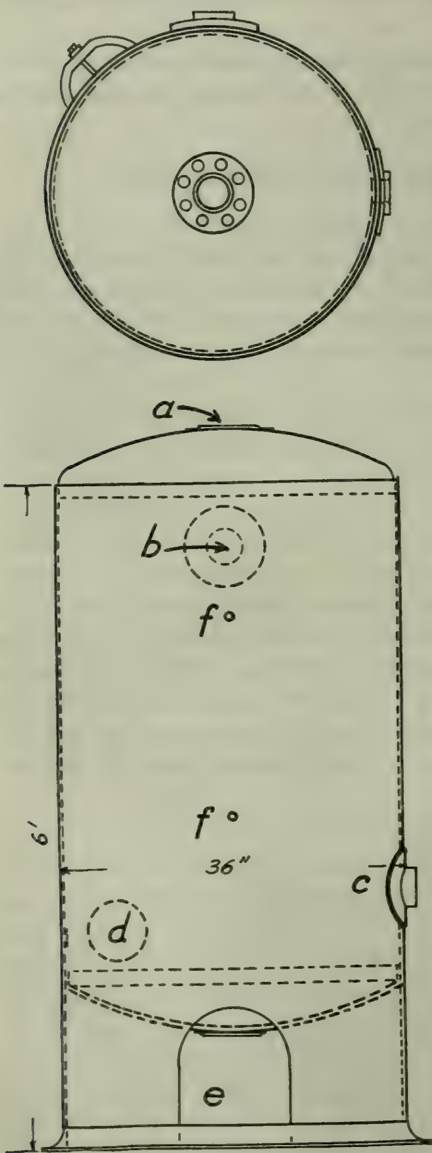


FIGURE 4.—Trap used with shallow pumping wells. *a*, gas outlet; *b*, gas and oil inlet; *c*, oil outlet; *d*, manhole; *e*, clean out; *f*, holes for gage glass.

TRAPS HELD UNDER VACUUMS.

This company had found that the crude oil during transportation and storage and in transfer to the stills of the refinery lost a part of the lighter fractions; also, the temperature used in cooling the still vapors permitted further losses of the lighter fractions, which could be collected as vapor and saved by treating in a compression plant with the gas and vapors produced at the wells.

The method adopted is to relieve the crude oil of its lighter gasoline fractions by holding a vacuum on the trap, as oil is sprayed or flows into it with the casing-head and tubing gases, and treating all the gas and vapors thus obtained in the compression plant. The condensate, which has a gravity of 86° B., is held under a pressure of 10 to 15 pounds and kept cool by shading or insulating the storage tanks until the product is blended with naphtha.

This company has three different production conditions to meet in the use of traps as follows: (1) Shallow pumping wells which have little or no gas pressure, (2) deep pumping wells with varying pressures of gas, and (3) deep flowing wells which have more or less pressure

on both gas and oil at all times and flow by head. Each condition is met by the use of traps of somewhat different design and operation.

Oil and gas from the shallow pumping wells is carried through flow lines, each controlled by a check valve, to a manifold, from which all the oil and gas goes through one line to a simple trap (fig. 4), the gas drawn out at the top at 5 to 15 inches vacuum to the scrubbers and vacuum pump, the oil being drawn off at a point near the trap bottom, to storage.

Production from deep wells flowing or pumping by "heads," which often builds up pressure in traps and lines by rushes of oil and gas too large for the normal capacity of simple traps and vacuum pumps, is handled by traps of special design, shown in figure 5. Two lines are laid from the well; one from the well tubing carries oil and gas pumped, or flowing together, the other line carries gas from between the casing and tubing. These lines are joined a few feet back of the trap intake, thus forcing all the gas and the oil to flow together into the trap at a point near the top; the gas separates from the oil and flows out at the top of the trap to the vacuum pump. The oil flows out near the trap bottom through a Crane balanced globe valve. The stem of the valve is rigidly connected to a counterbalanced float tank, which rises as the oil in the trap becomes low, closing the valve; fills and pulls the valve open when the flow increases and the oil rises in the trap. The float tank is connected both to the top and the bottom of the trap, as shown in figure 5, by swinging

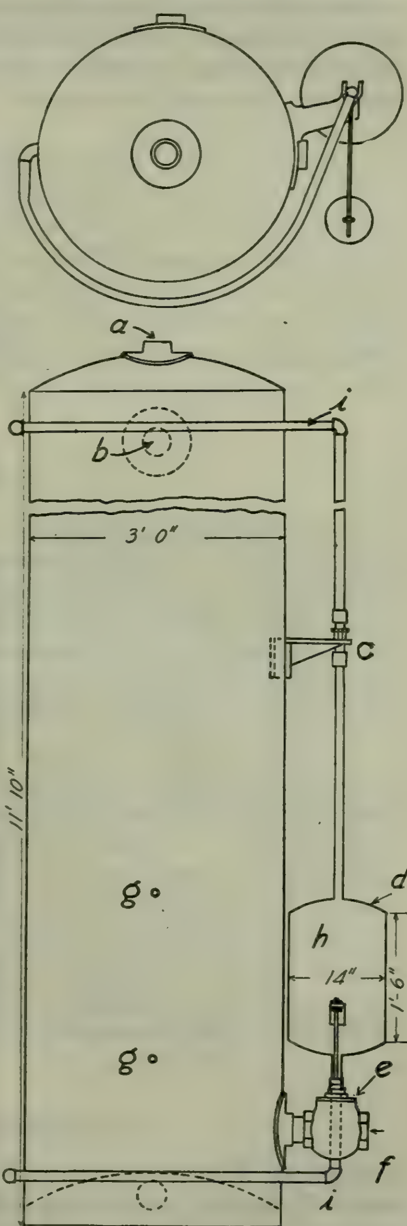


FIGURE 5.—Trap used on flow lines under pressure. *a*, gas outlet; *b*, gas and oil inlet; *c*, ball counter balance; *d*, float tank; *e*, 3-inch Crane balance globe valve; *f*, oil outlet; *g*, holes for gage glass; *h*, chamber; *i*, swinging pipe connections.

pipe connections. As the oil rises and falls in the trap oil flows in and out of the float tank through the bottom pipe connection. The top pipe connects the float tank and the top of the trap and acts only as a pressure equalizer. This trap is of standard design and is marketed by supply companies. The trap shown in figure 6 was

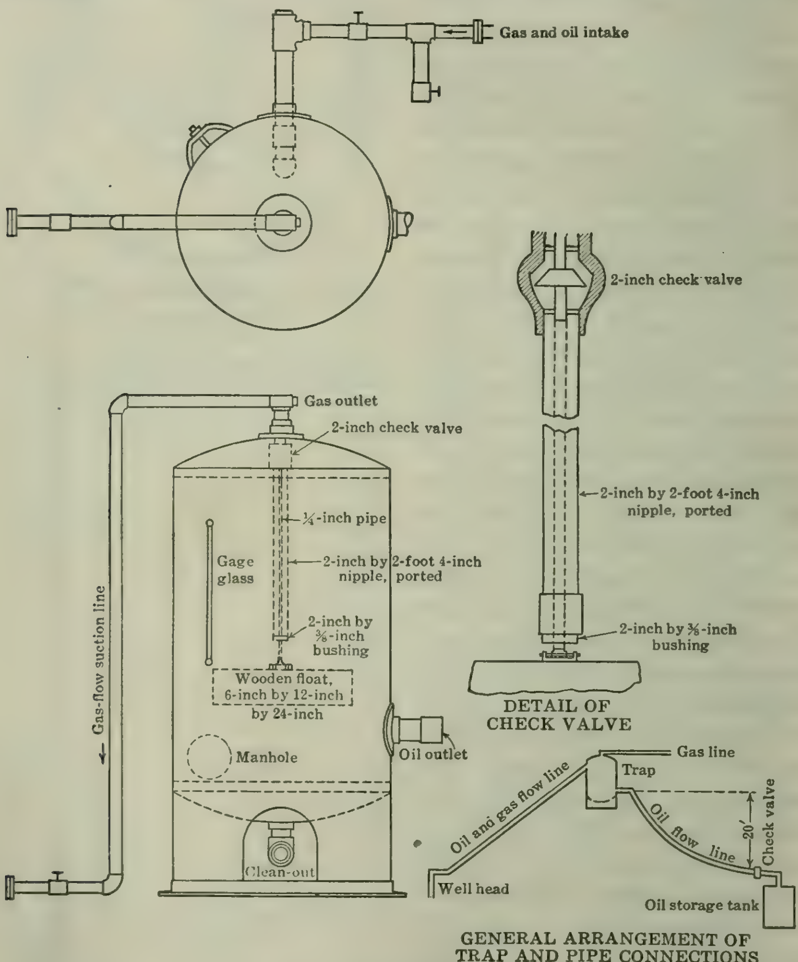


FIGURE 6.—Trap used with flowing wells.

designed by the company using this system of holding vacuums on traps. It is used, particularly with flowing wells, in much the same way as the trap shown in figure 5 and operates automatically.

When the oil level rises above a certain point the gas discharge shuts off entirely. This permits pressure to build up on both intake and discharge oil lines, causing a back pressure on the intake and a greater flow from the discharge; the trap thus clears itself and

returns to normal operation. It is set, as shown in figure 6, above both the well head and the storage tanks, so that when the oil and gas flow is small and a vacuum is built up in the trap the 20-foot drop and the horizontal check valve in the discharge line keep the oil from backing up into the trap, and permitting air to enter the trap and the gas lines.

As an example of loss of the light fractions of oil in storage, a 55,000-barrel storage tank filled with Cushing crude oil is reported by A. N. Kerr, of the Riverside Western Gasoline Co., to have lost by evaporation 9 inches, or 2.5 per cent of its total content, in one year. The loss, without doubt, consisted entirely of the light fractions that make up the gasoline content of the crude oil as it comes from the wells. Much of this loss might have been saved by using vacuum traps or by covering the tank and connecting it to the intake line of a compression plant.

FIELDS IN WHICH TRAPS ARE USED.

Traps are used more universally in the California fields than in other fields throughout the United States, because in California oil is sold on a gravity basis, making it desirable and profitable to retain as large a proportion of the light fractions as possible in the oil in order to keep the gravity at a maximum. The general practice, with the exception of the company using vacuum traps, previously mentioned, is to hold pressure on traps to save the light or gasoline fractions.

Plate I, *B*, shows a view of the Starke trap, designed and patented by Dr. Eric A. Starke, of the Standard Oil Co. of California, and used by that company.

Plate I, *C*, shows the McLaughlin compound trap, capacity 800 barrels of oil and 7,000,000 cubic feet of gas per day at 300 pounds pressure, patented by A. C. McLaughlin, of the Kern Trading & Oil Co., on the left, and the McLaughlin single-chamber trap, on the right. Plate III, *A* shows the cone chamber, McLaughlin trap.

Simple cylindrical traps used in the Fullerton field in conjunction with a casing-head gasoline plant are shown in Plate IV, *A*.

GATHERING LINES.

Gas from casing heads, tubing, traps, or flow tanks to be treated by compression is led through small (usually 2-inch) lines to a gas main that carries it directly to the plant or to a vacuum or pumping station.

At plants where the gas comes from near-by wells and the gathering lines are short, and it is not desirable to hold a high vacuum on the wells, the vacuum needed to carry the gas through the lines is

often developed in the low-pressure cylinder of the compression plant. By this method a vacuum pump is at many plants unnecessary, and the plant is simplified by requiring one less unit. From this condition the practice varies to plants at which gas is gathered from areas as large as 32 square miles, with 6 and 8 inch mains 7 to 10 miles long, and as many as 30 substations or gas pumps forcing gas through the pipe lines to the compression plant and holding the desired vacuum on the wells. In order to hold high vacuums on the wells from which gas is being drawn it is necessary to have the vacuum pump close to the wells, as it is impossible to maintain a minimum pressure through pipe lines of great length.

In designing a plant or plants to treat gas coming from a large area the number of plants, the number of vacuum and booster stations, the situation of the plant or plants, and the size and length of the pipe lines require careful mathematical calculations to determine the most economical installation. Many plants visited by the writer showed that little or no consideration had been given to these features. Such conditions may be due partly to the use of gas lines laid before the treatment of gas was considered and the reversal of the direction of flow in parts of such lines in order to bring the gas to the plant. The fall in pressure as the gas flows through the pipe lines and the increase in volume caused by the lowered pressure and the increased number of lead lines from wells as the gathering progresses toward the plant, make it essential to use pipes of progressively increasing diameter as the gas approaches the plant.

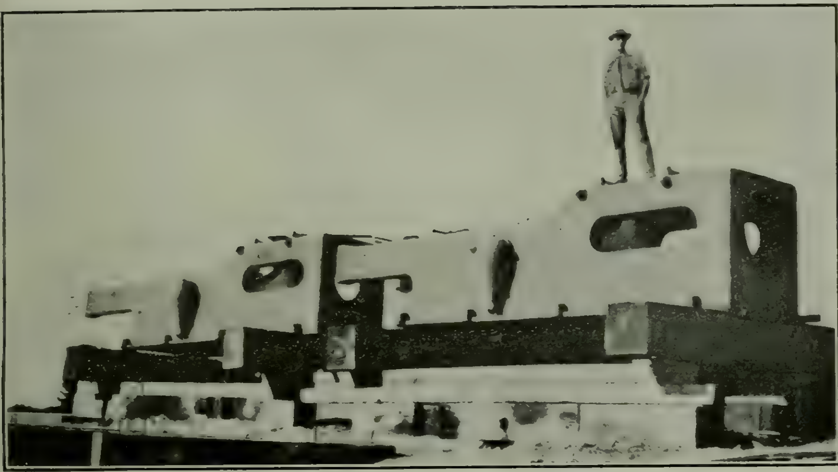
If vacuum pumps and booster stations are placed at points in the gathering lines to reduce the volume and increase the pressure of the gas, the lines leading from such plants may be smaller than those transmitting the gas under lower pressures.

In practice the sizes of gas mains have been determined usually by rule of thumb and bear little relation to the actual volumes, gravities, and pressures of the gas.

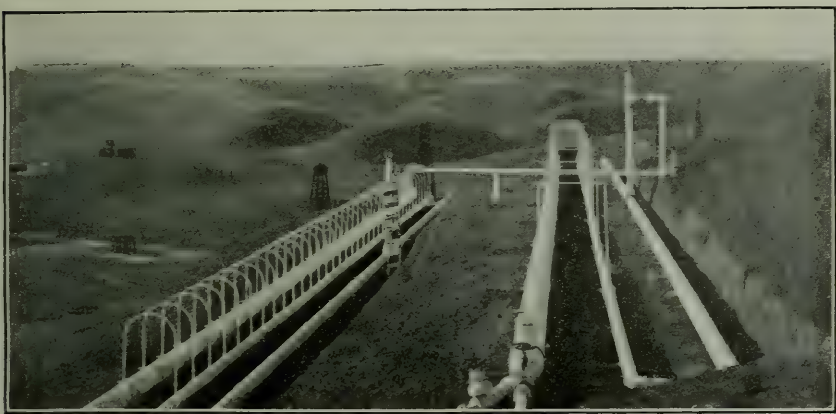
FLOW OF GAS IN PIPE LINES.

In designing gathering systems of compression plants to treat or pump gas, the determination of the proper size of pipe to use in lines for carrying a given quantity of gas at known pressures is so essential that the writer believes the formulas covering these points will be of value and interest to those engaged in compressing gas. Formulas and tables on the flow of gas in pipes have been developed by T. R. Weymouth, of Oil City, Pa., and discussed by him in a paper [a] written for and published by the American Society of Mechanical Engineers. These formulas, with that part of the paper that treats of the flow of gas in pipe lines, are given on pages 107 to 112.

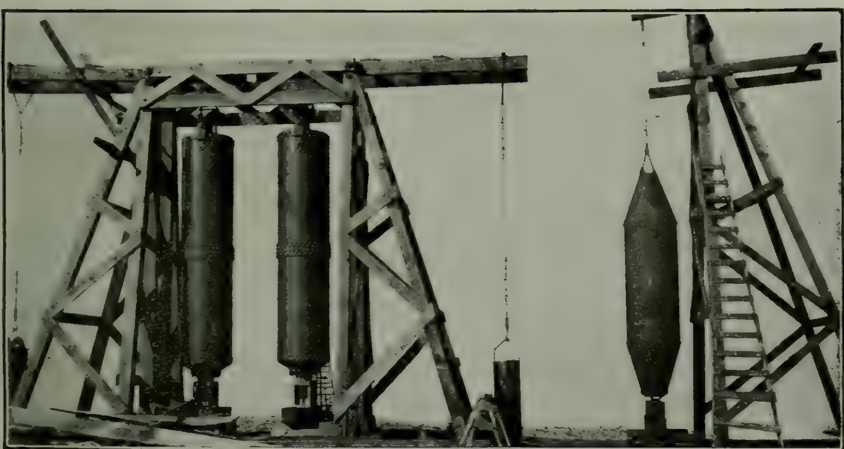
[a] Weymouth, T. R., Problems in natural-gas engineering: Trans. Am. Soc. Mech. Eng., vol. 34, 1912, pp. 185–234.



A. TWO SINGLE ENGINE-BED CASTINGS, WEIGHT 31,000 POUNDS EACH.



B. STARKE TRAP AND CONNECTIONS, USED WITH GUSHERS MAKING LARGE QUANTITIES OF OIL AND GAS.



C. McLAUGHLIN COMPOUND TRAP (ON LEFT) AND McLAUGHLIN SINGLE-CHAMBER TRAP (ON RIGHT).

A. VIEW OF COMPRESSION PLANT.

Note tanks at left and cooling tower at right of compressor building.

B. COMPRESSION PLANT, DAILY CAPACITY 7,500,000 FEET, BUILT ON SLOPING GROUND. HAS GRAVITY SYSTEM FOR HANDLING WATER AND CONDENSATE.

DRIPS AND SCRUBBERS.

Particles of crude oil are often carried into gas lines from flow lines, flow tanks, and traps; these, with fractions of heavy vapors condensed by changes in temperature and pressure of the gas in the transmission lines would, if not removed, cause trouble in the pipes, damage machines and meters, and discolor the condensate produced in the first-stage accumulators.

DRIPS.

Drips are placed at the low points in gas pipe lines to collect and remove condensed moisture and naphtha vapors and crude oil carried into the line, which if permitted to accumulate would restrict the passage and might do considerable damage by being forced through the line as a slug, forming a powerful hammer. The type of drip usually found is constructed of one or two lengths of 6 or 8 inch pipe capped at both ends and connected by a 1 or 2 inch pipe and valve, placed at the lowest point of a downward curve in the gas main. The liquids settling to this point drain into the drip and are either blown out and wasted, or, if the quantity and quality warrant saving, are collected in tanks and, after being distilled or filtered, are used for blending or are sold.

Officials of a plant visited by the writer gave the following data on "line distillates" collected by tank wagons from the gas-line drips:

Data on distillate collected from gas-line drips.

	Volume collected, gallons.
August, 1915	7,000
November, 1915	14,625
January, 1916	19,142
March, 1916	11,549
Average gravity for an entire year, 55° B.	

The figures represent the total quantity of condensate collected during the month named and show the direct effect of atmospheric temperature on the quantity precipitated. The product as collected was discolored, but as all the condensate produced was shipped to the refinery with the crude oil in pipe lines, the color of the line distillate was of no importance.

SCRUBBERS.

The term "scrubber," as used in the casing-head gasoline industry, is restricted in its meaning to tanks for settling liquids out of the gas or to tanks fitted with baffles or some form of filter for removing liquids or dust from the gas, and is not used, as in the coke-oven or the artificial gas industries, to designate equipment in which certain constituents are removed by chemical action or absorption in liquids.

The usual form of scrubber is a vertical tank (see Plate IV, B) varying from 3 by 6 feet to 6 by 20 feet in size, with a gas inlet in

the side and near the bottom, the end of the inlet pipe being turned downward or fitted with a baffle, so that the gas discharges toward the bottom. The gas rises through the tank slowly, thus permitting particles of liquid or dust to settle.

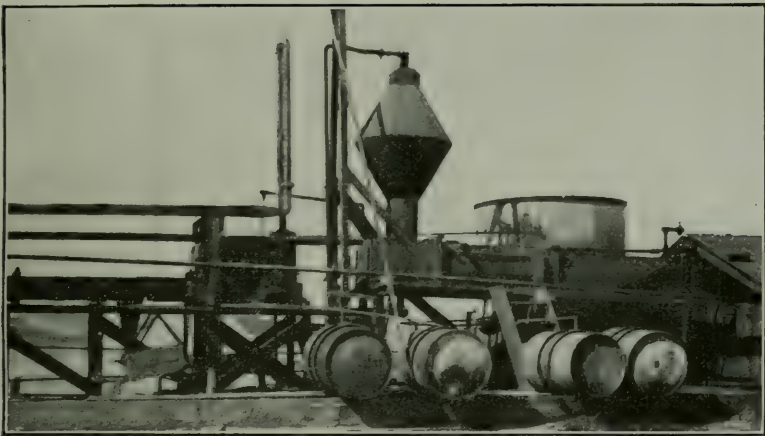
Scrubbers of the filter type are of the same size and form as the settling tank, but have perforated horizontal partitions on which are various filtering mediums such as moss, hay, or sponge. When the filtering medium becomes saturated or dirty it is removed and burned, if moss or hay, or is cleaned and replaced, if sponge is used. Scrubbers are always put in pipe lines ahead of compression machines, meters, and the pump. They also serve as intake receivers for the gas pump or the compressor, one tank, 3 by 6 feet in size, being used on the intake of each machine, or a tank of corresponding larger capacity for the entire plant intake.

VACUUM STATIONS.

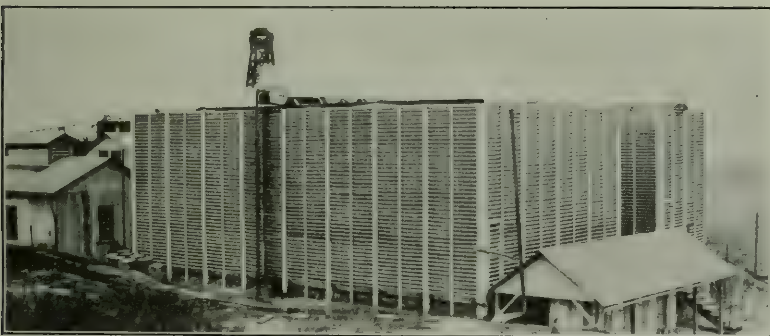
The number and the situation of vacuum pumps and booster stations on a gas-gathering system depend on the vacuum to be held on the wells, and the length and size of the pipe lines through which the gas is to be forced. When it is desired to hold the vacuum on the wells at the maximum, as is usual in the eastern fields, the vacuum pump must be placed near the wells, because friction, and often pipe-line leakage, reduces the suction on the well. The most common vacuum-pump installation consists of a gas engine of 35 to 70 horsepower belted to a duplex pump having cylinders varying between 10 by 17 inches and 20 by 20 inches. Intake pressures vary between 14 and 26 inch vacuums, and discharge pressures between a vacuum of 5 inches and a gage pressure of 5 pounds.

The "booster," if used, is to be placed in the same building as the vacuum pump. Power is developed by a 25 to 70 horsepower gas engine, either belted or direct connected to a compressor used to increase the pressure and force the gas through field lines either to another pump and booster or to the main compression plant. Compressors used in this way take gas directly from the discharge of the vacuum pump, usually holding a light (zero to 5-inch) vacuum at the intake, thus relieving the pump from working against high discharge pressures. Gas pumps are built too light to pump gas against pressures exceeding 10 pounds and usually discharge at nearly zero gage pressure. Compressors used as boosters deliver gas to the lines at pressures of 20 to 40 pounds and at any temperature incident to the compression.

Keeping gas under positive pressure through as much of the gathering system as possible tends to prevent air being drawn in and contaminating the gas, although any pressure high enough to keep air from leaking in also permits some gas, charged with condensable



A. McLAUGHLIN CONE CHAMBER TRAP.

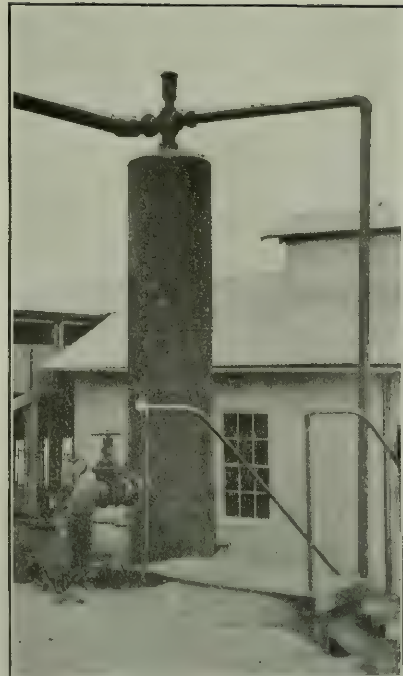


B. COOLING TANKS SET TO TAKE ADVANTAGE OF SLOPING GROUND AND OPEN-AIR CIRCULATION.

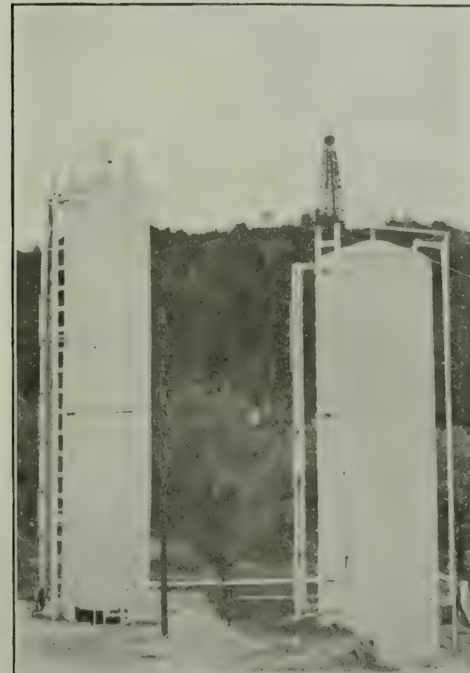
C. HIGH-PRESSURE AND LOW-PRESSURE ACCUMULATOR TANKS.

Note heavy double-riveted construction of high-pressure tanks.

A. SIMPLE CYLINDRICAL TRAPS.



B. INTAKE RECEIVER AT 1,000,000-FOOT PLANT.



C. "MAKE" AND STORAGE TANKS, SHOWING PIPING AND PRESSURE VALVES.

vapors, to escape. Air in gas cuts down the volume of gas treated, necessitates the use of higher pressures to precipitate the condensate, and carries varying proportions of water vapor which condense with the gasoline. Another advantage of transmitting gas under pressure is that pipe-line capacities are increased, making possible the use of pipe of smaller diameter in the gathering system.

There is a decided tendency at the present time in favor of welded joints in pipe lines to carry gas either at vacuums or positive pressures. It is claimed that lines with such joints cost less in upkeep and repairs and can be maintained practically gas tight.

SITUATION OF PLANT.

Factors entering into the problem of the best situation for a compression plant to treat gas from a given area are so numerous and varied that no rules which would apply even in a general way to all conditions found in oil fields can be given.

The most important factors and those which will have the greatest weight in determining the most practicable situation for a plant are: Water supply, transportation facilities, and the length of gathering lines and return dry-gas lines necessary. In eastern fields an ample water supply can usually be easily obtained from a creek, river, or well, and causes little concern to plant operators, but in the Mid-Continent and the western gas-producing areas the question of water supply often becomes of major importance.

In the California fields some plants pay as high as 3½ cents per barrel for water, which has to be treated or condensed before it is fit for use in boilers or jackets. Other plants pump their water for distances of several miles, and at these the cost of installation, operation, and upkeep of the pumps and the pipe lines make the cost of water an important item. One California plant is using water separated from the oil in a dehydration plant on the cooling coils, and is distilling and condensing water for jacket use, all other sources of water having practically failed.

It is obvious that the nearer the plant is to the center of gas production the smaller will be the size of the pipe lines and the amount of power required to conduct the gas to the plant. However, other factors, such as water-supply and transportation facilities may affect the choice of a site. The plant should be so situated as to suit best all conditions, each being considered in regard to the others. Compression plants are often built on a hillside, advantage being taken of the natural slope to install a gravity system of handling the water and the condensate. The water, being drained from all points of use to one pond or basin, requires only one pumping unit to return it to the top of the towers or the storage tank above the plant, from which it is drawn for all purposes. Plates II, *B*, and III, *B*,

show plants using a gravity system for handling water and condensate. In this system the condensate can be run by gravity from accumulators and "make" tanks to storage and blending tanks. The accumulators do not have to be set in pits or cellars; this is a decided advantage, because gasoline vapor may collect in such pits, unless they are thoroughly ventilated, in sufficient quantity to form an explosive or asphyxiating atmosphere and endanger the safety of the plant and the men. At plants visited by the writer three men have lost their lives by suffocation in pits filled with gasoline fumes. Some plants have a rule that a man before going into a cellar containing accumulator tanks shall notify another workman, or, if there is known danger from leaks, men shall work only in pairs or within calling distance of each other. Plants are often built on a hill or rise because of the better ventilation and the cooling effect on water towers and coils.

DATA ON PLANT PRACTICE.

A number of tables compiled from data taken at each of the plants listed in Table 2 or given to the writer by owners or by officials of the various companies are presented herein.

In Table 2, column 1 shows the field in which each of the plants is situated. Each plant is given a number, shown in column 2, which it retains throughout all tables and discussions following. Capacity and production data of these plants are shown in columns 3 to 5. Column 3 shows the quantity of gas treated, in thousands of cubic feet, as estimated by plant operators, or computed from meter readings, or from the compressor displacement and the number of revolutions, or the pipe-line capacities at measured pressures. Column 4 represents the production, after weathering, of unblended gasoline, and is approximately the quantity of condensate sent to market. Tank-car outage (or loss in transit) has not been deducted, as that factor varies widely with the distance traveled by the cars and the temperatures encountered during the shipment. Column 5 shows the number of gallons of condensate produced from each thousand cubic feet of gas treated, based on the plant capacity and the total product sold, as indicated in column 4. The gravity in degrees Baumé, as given in column 6, is determined from the plant product as a whole, before blending, or computed from the gravity of the blend, the quantity and the gravity of the blending stock used being known.

TABLE 2.—*Data showing situation, capacity, and output of the plants visited, and the gravity of the product.*

Field where plant is situated.	Plant No.	Capacity (in 1,000 cubic feet).	Daily production, gallons.	Gallons produced per 1,000 cubic feet of gas.	Gravity, °B.
California fields:					
Fullerton	1	1,000	600	0.60	68
Do	2	350	1,200	3.40	76
Do	3	450	700	1.50	78–80
Do	4	1,250	1,600	1.30	72–74
Do	5	5,000	1,200	.24	....
Santa Maria	6	2,500	5,500	2.20	81
Do	7	7,500	7,500	1.00	70
Do	8	500	500–600	1.00	70
Do	9	1,000	2,500	2.50	80
Do	10	750	1,200	1.60	74
Do	11	1,500	3,000	2.00	79
Do	12	700	1,500	2.10	81
Do	13	(a)	....	....	....
Ventura	14	1,000	2,000	2.00	86
Do	15	....	800	....	....
Salt Lake	16	250	325	1.30	65
Do	17	750	840	1.10	60–65
Do	18	....	1,500	....	68–70
Midway	b 19	1,800	1,400	.78	68
Do	20	1,500	1,400	.90	67
Do	b 21	1,000	700	.70	80
Eastern fields:					
Bradford, Pa	22	600	1,200	2.00	96
Sistersville, W. Va	23	200	800	4.00	88
Do	24	375	1,500	4.00	90
Do	c 25	....	....	....	....
Do	26	500	....	....	88
Southern Illinois	27	750	500	.75	83
Do	28	....	200	....	83
Do	29	....	....	....	....
Mid-Continent fields:					
Glenn pool	30	750	3,000	d 4.00	....
Do	31	375	1,500	d 4.00	77
Do	32	3,000	22,500	7.40	84
Do	33	1,800	9,000	5.00	82
Do	34	750	5,250	7.00	82
Do	35	350	1,590	4.52	96
Do	36	2,000	2,310	1.10	78
Do	37	400	2,565	6.40	85
Do	38	750	5,055	6.70	....
Do	39	200	510	2.50	....
Do	40	250	600	2.40	....
Do	41	350	550	1.60	....
South Glenn pool	42	450	1,200	2.40	....
Morris	43	300	300	1.00	....
Do	44	500	1,850	3.60	....
Beggs	45	350	710	2.10	....
Muskogee	46	300	730	2.44	....
Do	47	350	300	.85	....
Glenn pool	48	1,200	2,380	2.00	....
Cushing pool	49	2,000	2,810	1.40	....
Cleveland	50	1,200	2,000	1.67	....
Muskogee	51	250	925	3.70	....
Do	52	250	500	e 2.00	....
Cushing	53	....	....	....	....
Nowata	54	f 2,250	10,000	4.00	....
Do	55	1,250	1,600	1.30	....
Do	56	380	600	1.60	....
Do	57	830	1,500	1.60	....
Morris	58	2,000	3,000	1.50	....
Do	59	400	725	1.90	....
Nowata	60	1,000	1,900	1.90	....
Do	61	500	1,100	2.20	....
Do	62	280	420	1.50	....
Glenn pool	63	487	1,948	g 4.00	....
Do	64	515	2,062	g 4.00	....

[a] Plant not in commission.
[b] Plant capacities doubled and expansion sets installed or improved; product per 1,000 feet of gas increased.
[c] At this plant gas is compressed in one stage to a pressure of 150 pounds.
[d] Estimated.
[e] Eight per cent water with high and low pressure product.
[f] Thirty per cent air.
[g] Volume of gas estimated from product at 4 gallons per 1,000 cubic feet, a conservative estimate for gas from wells in the Glenn pool.

TABLE 2.—*Data showing situation, capacity, and output of the plants visited, and the gravity of the product*—Continued.

Field where plant is situated.	Plant No.	Capacity (in 1,000 cubic feet).	Daily production, gallons.	Gallons produced per 1,000 cubic feet of gas.	Gravity, °B.
Mid-Continent fields—Continued.					
Glenn pool	65	90	350	a 4.00	
Do	66	90	351	a 4.00	
Do	67	98	384	a 4.00	
Do	68	136	545	a 4.00	
Do	69	125	500	a 4.00	
Do	70	141	566	a 4.00	
Do	71	712	2,864	a 4.00	
Do	72	375	1,500	a 4.00	
Do	73	466	1,864	a 4.00	
Do	74	124	496	a 4.00	
Do	75	173	690	a 4.00	
Caddo (Louisiana)	76	2,000	3,600	1.80	79
Do	77	400	640	1.60	79
De Soto (Louisiana)	78	45	350	7.00	73
Caddo (Louisiana)	79	250	1,050	4.20	b 80
New Jersey:					
Refinery	80	1,750	5,400	3.09	76–93

a Volume of gas estimated from product at 4 gallons per 1,000 cubic feet, a conservative estimate for gas from wells in the Glenn pool.
b 50 per cent of this product was from low-pressure cylinder and 50 per cent from high-pressure cylinder and expansion coil.

In the following pages the writer has endeavored to describe as nearly as possible the treatment of natural gas in the recovery of gasoline by the compression process, and the mechanical units used.

The controlling functions of low and high pressure compression units of the plants studied by the writer are shown in Table 3.

Plant 2 is described in detail in pages 63 to 65. Plant 5 is a gas-pumping station, the condensate collected in cooling the gas before transmission is noted as production in Table 2 (p. 29). This gas after transmission through the pipe lines is treated in an absorption plant. Plant 10 uses three-stage compression. Plant 25 uses one-stage compression, compressing to a pressure of 150 pounds. Plant 80 is a refinery at which uncondensed still vapors are treated by compression; this plant is described in detail in later paragraphs.

PLANT INTAKE.

Table 3 shows that the temperature and the pressure at the plant intakes vary widely. The pressures tabulated as pressure at plant intake represent the pressure shown at the suction of the first-stage compression cylinder. Vacuum pumps, even if installed at the plant, are considered as part of the gathering system, and vacuum at plants where the compression cylinders are used to hold vacuum on the gathering system is taken as part of the compression operation and not as a part of the gathering system to which it rightly belongs. The intake pressures used vary from 18-inch vacuum to 5-pound pressure, and the temperatures from 60° to 125° F., the average

pressure being approximately that of the atmosphere, and the average temperature 80° F. The temperature of 60° F. noted above was recorded at plant 1, where the gas is cooled in coils placed in a water tower before it is compressed, and the temperature of 125° F. at a plant where a vacuum-pump discharge is used as the first-stage suction without cooling.

PRECOOLING.

Cooling the gas before it enters the first stage of compression, although not generally practiced, has distinct advantages. Reducing the temperature of the gas decreases the volume, the intake pressure remaining the same, so that more gas is taken into the compressor cylinder at each stroke, thus increasing the efficiency.

In warm climates plants having gathering lines, traps, and scrubbers exposed to the sun, which may heat the incoming gas to temperatures higher than 110° F., or having gas pumps and "booster" compressors in the gathering systems with no cooling coils after such units and before the plant intake, can by installing coils or other cooling apparatus increase both the plant efficiency and the carrying capacity of the pipe lines. Cooling the intake gas 30° or 60° F. will increase the quantity treated by a compression unit 5 to 10 per cent and lower proportionally the temperature of the gas discharged from the compressor. (See Table 11, p. 112.)

A plant in California lowered the temperature of the gas about 40° F. by passing it through a water-cooled coil ahead of the low-pressure intake. On the day of the writer's visit 1,250,000 cubic feet of gas was handled and the temperature lowered from 114° to 74° F. The coil used consisted of twelve 3-inch pipes 25 feet long, in 10-inch headers, placed horizontally in the cooling tower below the high and the low pressure gas coils.

A plant in Louisiana uses water cooling ahead of the vacuum pump and the first-stage compression intakes. In gas transmission gas piped to market is always cooled before being permitted to enter the mains, in order to increase the capacity of the line and to precipitate as much condensate and water vapor as possible.

TABLE 3.—*Data on compression.*

Plant No.	Low-stage compression.									High-stage compression.						
		Intake.		Discharge.		Cooling coils.				Compressor discharge.			Cooling coils.			
	Rated horse-power.	Pressure, inches of vacuum.	Temperature, °F.	Pressure, pounds per square inch.	Temperature, °F.	Total surface area, square feet.	Square feet per horse-power.	Square feet per 1,000 feet of gas treated.	Discharge temperature, °F.	Pressure, pounds per square inch.	Temperature, °F.	Rated horse-power.	Total surface area, square feet.	Square feet per horse-power.	Square feet per 1,000 feet of gas treated.	Discharge temperature, °F.
1		10–15	60	40		500		0.500	60	220			500		0.500	60
2		11		37	(a)											
3	55	2	(b)	55		220	4.00	.490	68	250		55	220	4.00	.490	68
4	150	3–10	72	50	240	587	3.91	.470	70	240	240	150	587	3.91	.470	70
6		0–1.4	78	54	200	1,225		.500	81	250	190		1,225		.500	70
7	900	6	80	35	245	3,600	4.00	.481	76	250	245	900	3,600			78
9	160	10	80	25		475	2.97	.475		200		160	475	2.97	.475	
10		7		c 12 d 80		975		c .920 d .480		250					(e)	
11	240	2–5	65	36	240	585	2.43	.390	65	190	235	240	585	2.43	.390	72
12	160	5	65	43		450	2.80	.640	70	225		160	450	2.80	.640	70
14	165	(f)	(b)	50	200	504	3.05	.504	70	250	200	165	504	3.05	.504	70
16	50	9	(b)	40		167	3.35	.670		240		50	167	3.35	.670	
17	150	13	(b)	35		420	2.95	.590		235		150	420	2.95	.590	
19	262	6	68–80	35	250	660	2.87	.370	78–80	275	260	262	660	2.87	.370	70–80
20	247			50						275		247				
21	150	g 3	78	50	250	528	3.50	.528	68	250	250	150	528	3.50	.528	68
22	90	2–18		40	190	146	1.63	.244	130	300		90	292	3.26	.488	60
23	17	15		15		100	5.90	.500		90		17	150	8.80	.750	
24	35	12		10						100		35				
26		5		25						120						
27	100	6		50		(h)				300		100	350	3.50	.480	70
28		5														
29		5		60		(h)				300		25	190	7.60		70
30	105	12		50		375	3.60	.501		270		105	882	8.42	1.20	
31	55	(b)		50		220	4.00	.590		250		55	220	4.00	.590	
32	350	(b)	(b)	50	160	880	2.51	.292	94	250	i 210	350	880	2.51	.292	96
33	280	5	(b)	40		670	2.40	.370	(b)	225		280	670	2.40	.370	(b)
34	150	5		45		733	4.90	.975		215		150	1,260	8.40	1.68	
35	50	3		45		210	4.20	.600		250		50	420	8.40	1.20	
36	240	6		45		840	3.50	.420		250		240	1,260	5.25	.630	
37	85	0–5		45		210	2.47	.520		245		85	410	4.94	1.40	

38	150	5	...	45	...	315	2.10	.420	...	250	...	150	380	2.56	.50	...
50	160	0	...	45	...	780	4.85	.650	...	250	...	160	1,470	9.20	1.23	...
51	55	6	...	45	...	147	2.70	.590	...	250	...	55	286	5.20	1.14	...
52	50	9	...	25	...	210	4.20	.840	...	250	...	50	610	12.4	2.44	...
53	...	5	...	45	...	...	...	...	...	250	...	...	...	...	...	...
54	450	8	...	40	...	610	1.35	.270	...	275	...	450	975	2.16	.43	...
55	150	0	...	48	...	505	3.36	.404	...	250	...	150	505	3.36	.404	...
56	105	4-8	...	40	...	505	4.80	1.36	...	300	...	105	505	4.80	1.36	...
57	175	4-8	...	40	...	840	4.80	1.01	...	250	...	175	840	4.80	1.01	...
76	300	4-5	70-76	80	200	1,760	5.9	.88	60	(j)	...	...	...	...	...	...
77	50	g 3	70	90	200	590	11.80	1.47	65	(j)	...	...	...	...	...	...
78	50	0 2	80	75	200	590	11.80	13.00	80	(j)	...	...	...	...	...	...
79	52	0	125	50	225	126	2.42	.50	75	250	130	52	252	4.84	1.10	72
80	...	g 1	70	43	225	283	...	.189	80	160	225	...	566	...	.378	70

a Ammonia process used from this point on.
b Atmospheric.
c Low-pressure cylinder; three stages used.
d Intermediate cylinder.
e 0.920, low compression; 0.480, intermediate compression.
f Varied from positive pressure of 5 pounds to vacuum of 5 inches.
g Pounds, positive pressure.
h No coils used between low-stage and high-stage compression.
i At coil intake.
j Single-stage plant, no blend ng.

FIRST-STAGE PRESSURES AND TEMPERATURES USED.

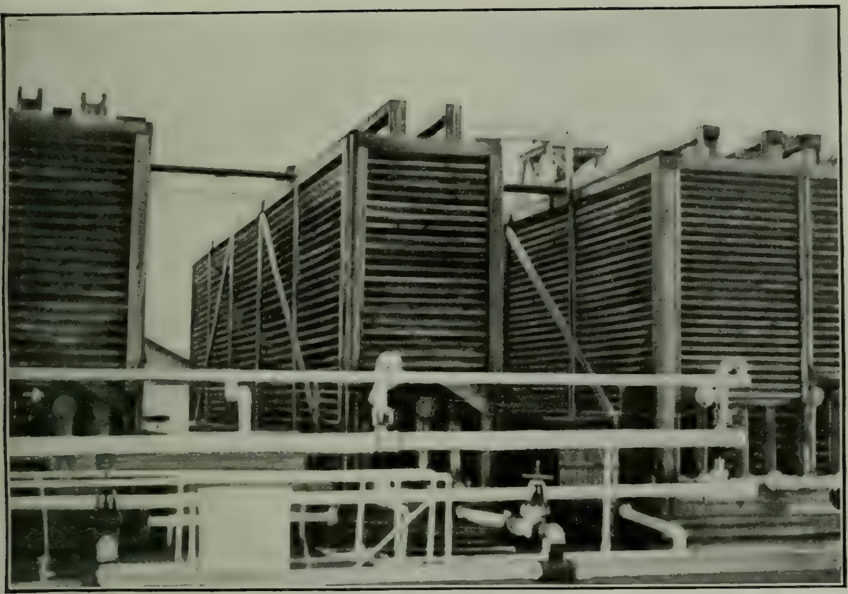
In plants using two-stage compression, the average pressure developed by the first stage is between 40 and 50 pounds per square inch; the temperature rises to between 200° and 250° F., depending on the temperature of the gas at the compressor intake and the number of compressions developed.

The increase in temperature of the gas from compression is a function of the power used to raise the pressure to the desired point. The power used depends on the number of compressions through which the gas is forced between its initial and final volume. As the amount of power actually expended, and not the initial and the final pressure, determines the rise in temperature the temperature increase due to a given number of compressions should be the same. If the intake temperatures of the high and the low stage compressor cylinders are equal, the final, or discharge, temperature of both cylinders of a two-stage compressor or of two single-stage machines acting as a high and a low stage unit should be the same, provided they are of equal horsepower and working properly and under uniform conditions. This is found to be approximately true in plant practice, as is shown by the temperatures of the compressor discharges given in Table 3.

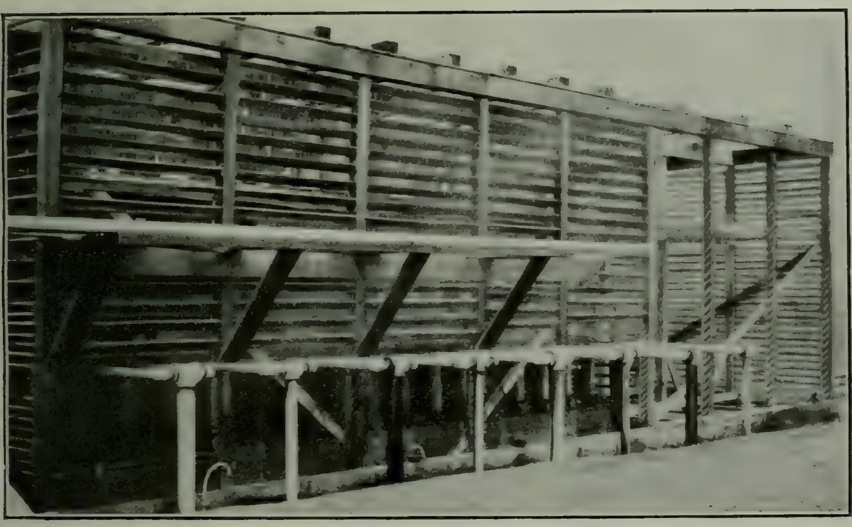
The line carrying the compressed gas from either the high or the low stage cylinder is usually fitted with safety valves set to pop at pressures of 5 to 20 pounds above the desired pressure in order to protect the machine in case a valve farther along in the system may have been left closed or a pipe in the coils or other units in the gas circuit should become stopped or clogged, thus causing pressure to build up throughout the system. In plants using expansion engines this condition may occur at any time through the engine valves freezing, thus stopping the usual discharge.

ATMOSPHERIC COOLING.

The compressed gas discharged from the compressor is carried through an oil separator, placed just ahead of the cooling coils, which traps any lubricating oil vaporized in the cylinders or carried mechanically with the gas, the oil being condensed by the time the gas reaches the trap. Cooling to this point is effected by radiation to the atmosphere surrounding the gas discharge pipe and to the jacket water around the compressor cylinder. Some operators are employing air cooling extensively in order to save water, the practice being to use a much larger pipe, exposed as far as possible to the atmosphere, for conveying the hot gas from the compressor discharge to the water coils, thereby reducing the speed of flow and so increasing the time of transmission that the temperature of the gas is materially lowered. One plant with a daily capacity of 1,250,000 feet and using 6-inch pipe to carry both high and low



A. COOLING TOWERS, MANIFOLD INTAKE, AND DISCHARGE LINES AND HEADERS.



B. HIGH AND LOW PRESSURE COILS WITH INTAKES ALTERNATING.

pressure gas to the coils, reduces the temperature between the compressor discharge and the coil intake 80° (240° to 160° F.) even in warm weather. In cold weather the reduction is greater.

Methods of air cooling are being rapidly developed and installed in districts where water is scarce and expensive, or the supply uncertain.

COOLING COILS.

In the eastern fields the cooling coils are generally of the continuous, submerged type, consisting of a 2-inch pipe 20 feet long, submerged in a tank of water. The total length of the coil varies between 300 and 500 feet, and the radiating area is 0.6 to 0.7 square feet per 1,000 cubic feet of plant capacity, and 2 to 5 square feet per horsepower used in compression. A continuous flow of water through the tank cools the gas to approximately the same temperature as the water.

In western and Mid-Continent practice a different method has been developed. Because of the difficulty of obtaining a continuous supply of cool water, it is necessary to use the same water over and over again in a closed circuit, the water being cooled in towers or in sprays over the principal storage pond or basin.

COOLING WATER BY EVAPORATION AND RADIATION.

Water exposed to air cools in two ways—by radiation, as long as the water is warmer than the air, and by evaporation.[a] To obtain the greatest cooling effect the water must be so exposed to the air as to present the greatest possible surface. At some plants the water is cooled in towers (Pl. V, *A*) by means of sprays, or by permitting the water to fall in small streams on wire netting or screens, usually placed above the coils, thus atomizing the water and presenting a large surface to the air. The falling spray is often collected by V-shaped troughs that are placed a few inches above the top pipe of the coil and direct the flow of cooled water over the entire series of pipes. The water, dripping from the lowest pipe of the coil, is collected in a shallow basin beneath the coil and the tower, pumped to the top of the tower, and used again.

Plates VI and VII show views of a compression plant and the general arrangement of towers, compressor building, and storage tanks.

Some plants use a spray over a pond. The water is collected beneath the coils and conducted to a cistern from which it is pumped through upward sprayers placed over the storage pond, thence it is again pumped over the coils. The finely divided particles of water in the spray are cooled by radiation and evaporation while falling into the main body of water below. This system, although producing

[a] Hausbrand, E., Evaporating, condensing, and cooling apparatus, 1903, 400 pp.

satisfactory temperatures, wastes more water than the tower installations, more being carried away mechanically by the wind; there is also a waste due to seepage, if the pond is of earth. The surface of the water in the pond is often exposed to the heat of the sun, which warms the body of water after cooling and before use over the coils. The sun has a decided effect in raising the temperature of the water in regions where the weather is warm during a large part of the year, as in Oklahoma and southern California.

WATER COOLING IN TOWERS.

In towers, during hot dry weather, temperatures 10° to 40° F. below that of the atmosphere are at times obtained with minimum losses of water. Many plant operators who have not experimented to find the amount of water that gives the lowest temperature to the gas being treated, use far more than is needed or gives the best results. Water falling in excessive quantities in a tower does not acquire the lowest possible temperature from radiation or evaporation, and the large bulk of water flowing over the coils can not cool the gas as efficiently as a smaller amount does, for the same reason. The best results are obtained when minimum quantities of water are circulated and finely divided while passing downward through the tower. Only enough of the cooled water should be directed onto the pipe coils to keep all parts thoroughly wet, thus giving the water the greatest possible opportunity to evaporate.

The use of auxiliary cooling agents such as ammonia or ammonia and brine is discussed later in connection with the descriptions of plants using such methods.

It may be of interest and use to operators to note here the latent heats of vapors being treated in the cooling coils. Burrell[a] gives the following values for the latent heats of some petroleum distillates:

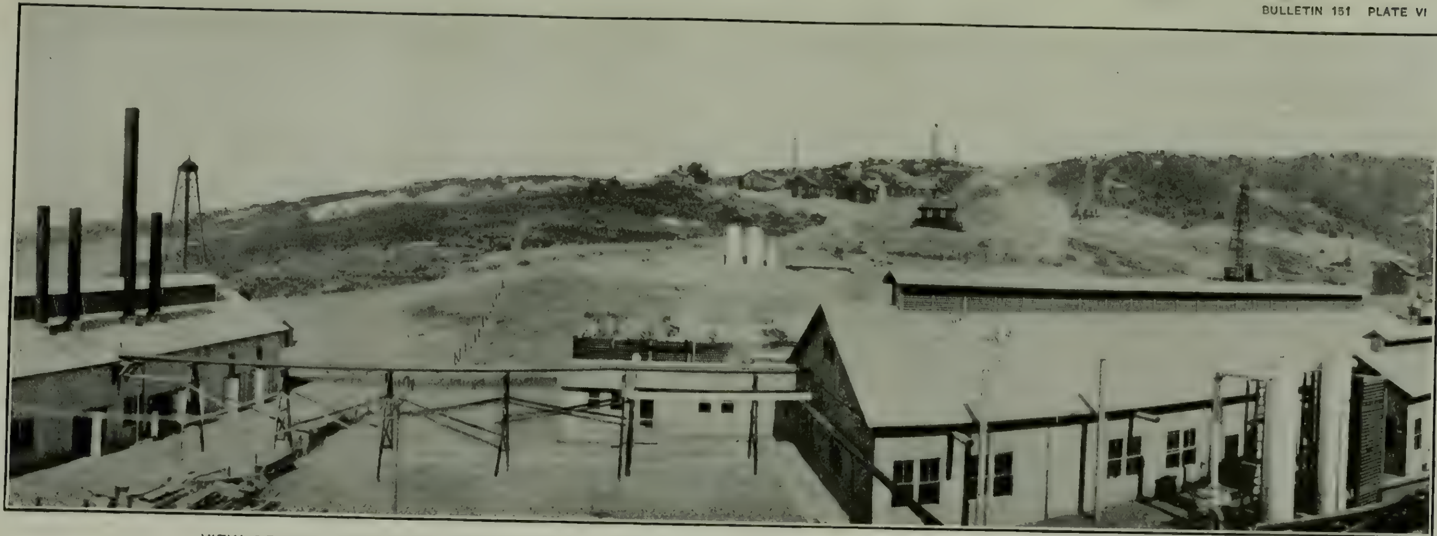
Specific gravities and latent heats of four distillates.

	Specific gravity, °B.	Latent heat, B. t. u. per pound.
Kerosene	43	105
Naphtha	56	103.5
Gasoline	65	100.6
Gasoline	89	100.2

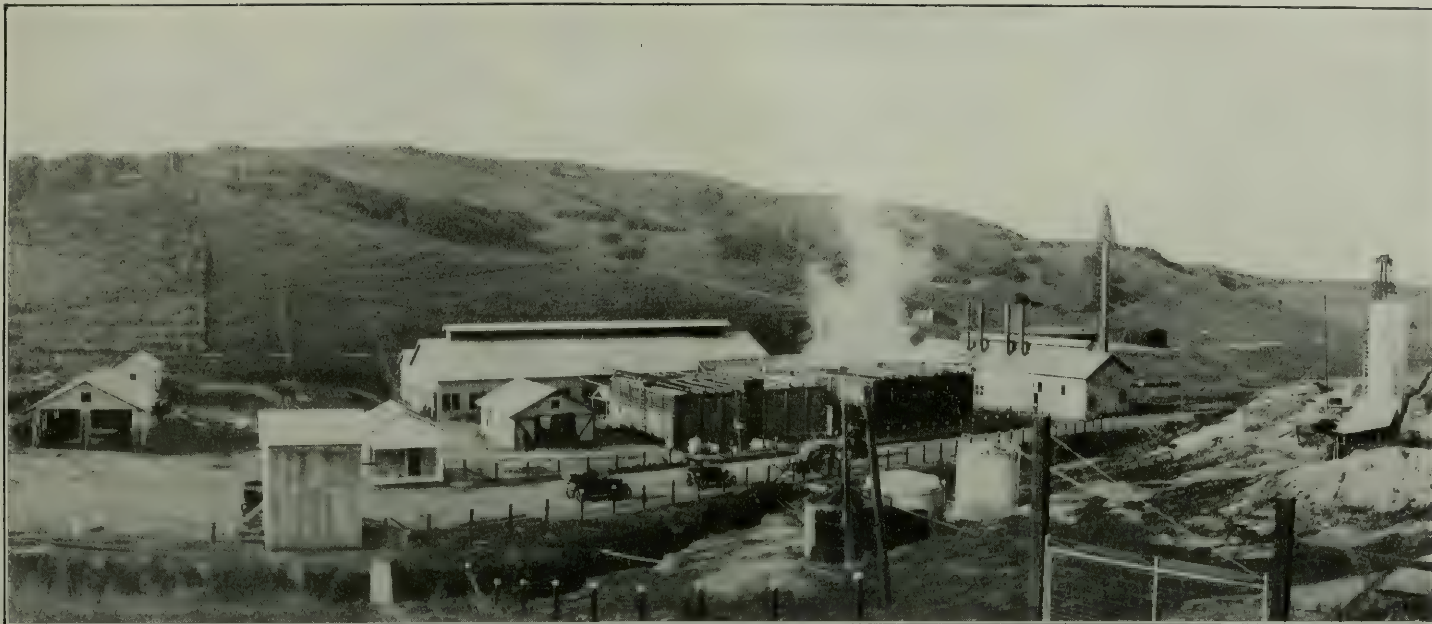
In gasoline computations it is customary to use as the latent heat 100 B. t. u. per pound. Kent gives the specific heat of liquid gasoline of specific gravity 0.68 to 0.70 as 0.53 to 0.55, and Lucke[b] quotes Regnault as stating that methane gas has a specific heat of 0.5929 at constant pressure and 0.4505 at constant volume.

[a] Burrell, G. A., Personal communication.

[b] Lucke, C. E., Engineering thermodynamics, 1912, p. 578.



VIEW OF 2,500,000-FOOT PLANT SHOWING ARRANGEMENT OF COMPRESSOR BUILDINGS, TOWERS, AND STORAGE TANKS.



ANOTHER VIEW OF PLANT SHOWN IN PLATE VI.

TYPES OF COILS AND CONNECTIONS USED.

Two systems of pipe connections are used between compressor discharges and cooling coils. In one system all low-stage compressors, and likewise all high-stage compressors, discharge the compressed gas into a common pipe or manifold, from which it is distributed by a manifold to the different sets of coils being used to cool the hot gas. (See figure 9, page 50.) The other system is to lead the gas discharged from each cylinder through a separate coil which cools only the gas from that compressor, the gas treated by each unit being kept separate throughout its entire circuit. The first method has the advantage of permitting one coil to be shut down or cut out for repairs while the compressor is running, the discharge from that machine being cooled in the coils still in use, or conversely, the coil may remain in use while the compressor is idle, and treat gas from other units. In the second method of connection if any coil or machine is out of commission the entire unit of which it is a part must be stopped, causing more of the plant to be idle.

Throughout the districts making natural-gas gasoline the 2-inch pipe in cooling coils is standard, and only a few plants using other sizes were found by the writer.

Systems and methods of connection vary widely, ranging from continuous return-bend coils in which all of the gas passes through the entire coil, to coils which divide first into two or more headers, and then into numerous separate pipes. In the multiple-header system each portion of gas passes through short lengths (20 to 80 feet) of the coil, and is again collected by headers before going to the accumulator tank and to the next stage of treatment. In the continuous system the gas passes rapidly through the total length of pipe, its temperature being reduced during the whole time of travel from end to end of the coil. In the multiple method the rate of flow in each pipe is reduced in proportion to the number of pipes used, so that the gas is sufficiently cooled while traveling through such a short length of coil.

There is much difference of opinion among operators as to which method gives the more satisfactory results. Many of the newest plants combine the two methods, as follows: Each coil unit is divided at the intake by a header into 3 to 12 sets of 2-inch continuous return-bend coils, each being 4 to 16 pipes high, and generally 20 feet long, depending on the cooling area desired. The intake header is placed horizontally at the top of the coil so as to allow the gas to travel downward in the same direction as the condensate. At the lower end of each set of return-bend coils the gas and condensate are again collected in a header before passing to the accumulator tank. Coils of this type and of the single-pipe continuous type have

the great disadvantage of being "hard to get at" in case any length of pipe in the coil needs replacement, whereas in multiple-header coils in which the ends of each pipe are packed in a gland, any member can be removed or replaced without taking down any other part of the coil.

DIRECTION OF FLOW OF GAS AND CONDENSATE.

It is universally conceded that the direction of flow of gas and condensate should be parallel and not countercurrent. As the liquid will drain toward the lowest point in the coil, the gas must enter at the top in order to flow with the condensate. As an illustration of the effect of counter flow, a plant in the Caddo field using a countercurrent flow of gas and condensate in the water-cooled coils produces no condensate whatever in the accumulator tank at the end of these coils. The gas yields 11.8 gallons of condensate per 1,000 cubic feet treated, but this condensate is all precipitated in double-pipe condensers cooled by expanded gas to a temperature of 38° F., in which the flow of gas and liquid are parallel. Undoubtedly some condensate would be precipitated in the water-cooled coil if the direction of gas flow was reversed. Other plants have obtained similar results under like conditions; one example being a California plant, in which the coil discharge pipe sloped upward to the accumulator tank, permitting condensate to gather in the bottom coils and discharge pipe and be constantly in contact with flowing gas. The accumulator tank was lowered so as to allow a drop in grade from the coils, with the result that the yield of condensate at that point increased noticeably. It seems that the condensate on long and intimate contact with the gas as above described, is again taken up by the gas as a vapor, even at high pressures, and carried to some point more conducive to precipitation and separation.

That condensate vaporizes in accumulator tanks has also been proved and has given rise to the practice of trapping off the liquid as soon as collected. Because of the facts stated, it appears to be the best and most productive practice to separate the gas and condensate as soon as possible after all the condensable fractions have been precipitated and always to allow the gas and condensate to flow in the same direction. If the above arguments hold true under all conditions, it would seem to be advisable to divide the gas to be cooled into a number of coils or pipes that will retain it only long enough to obtain the maximum cooling effect from the water used, and to separate the gas and condensate as soon as possible.

In order to divide the gas from a header equally in each of the coils or pipes of a coil, an orifice disk is sometimes placed in the intake from the header; the constriction causes a slight back pressure, forcing the gas to enter each coil in approximately equal quantities. The

size of the orifice is arbitrarily determined by making the sum of the areas of the orifice openings equal to the cross-sectional area of the pipe leading the gas to the header from the compressor discharge or the discharge manifold, as the case may be.

RADIATING AREA OF LOW-PRESSURE COILS.

In Table 3 the total surface areas of coils used in cooling gas from low-stage cylinders of various plants visited by the writer are tabulated, with the area per 1,000 cubic feet of gas treated per day; also, the area per horsepower used in compression. The average area of coil is between 0.6 and 0.7 square feet per 1,000 cubic feet of gas treated daily and nearly 3.5 square feet per horsepower used in compression. The latter factor is more useful for plant design, as the heat developed in compressing gas is a function of the power used in compression and not of the volume of gas being treated. A cooling area of 4 square feet per horsepower is usually used at gas-pumping plants and has proved satisfactory in most fields.

Column 10, Table 3, gives the temperature of the gas leaving the low-stage water-cooled coils at plants where such data was recorded and available. Minimum temperature should be maintained to precipitate the maximum percentage of condensate and benefit high-stage compression, as explained in previous paragraphs.

From these coils the gas passes to the low-stage accumulator tanks. Each coil may be provided with a separate tank or all the coils may be manifolded to one tank. Plate III, *C* (p. 26), shows the alternate arrangement of accumulator tanks of high and low pressure coils, each coil having a separate tank. The tanks are usually 3 to 4 feet in diameter by 6 to 10 feet high. The gas is led in at the side of the tank and near the top through a pipe turned or baffled downward inside of the tank, discharging at a point about midway between the top and bottom. The condensate settles to the bottom; the gas discharges at the top to the intake line of the high-pressure cylinder if each unit is independent or to the high-pressure intake manifold if that system is used.

High and low pressure coils, with intakes alternating, used at one plant are shown in Plate V, *B* (p. 34).

PRODUCTION FROM LOW-PRESSURE TREATMENT.

The proportion of condensate collected in the low-stage accumulator tanks averages 15 to 30 per cent of the total yield and varies between nothing and 40 per cent, depending on the content of condensable fractions in the gas and on the temperature and the pressure used. Some operators permit condensate to accumulate in the tanks until the entering gas is forced to pass through it, or to accumulate for a given time, and then run it into the storage tank through a hand valve.

The general practice, however, based on the theory that to separate gas and condensate as soon as possible produces the best results, is to remove the condensate from the accumulator tanks continuously with a small automatic trap that dumps often and with but little agitation keeps the tank practically empty at all times.

HIGH-PRESSURE TREATMENT.

From the low-pressure accumulator tanks the gas passes into the high-pressure cylinder of the compressor, and the cycle is repeated except that the higher pressure causes the lighter hydrocarbons to condense.

RADIATING AREA OF HIGH-PRESSURE COILS.

Table 3, which gives the average surface areas of both high and low pressure cooling coils at the plants visited, shows that a somewhat larger cooling area is used for the high-pressure gas. The area of high-pressure coils per 1,000 cubic feet of gas cooled daily was between 0.7 and 0.8 square feet and about 4.5 square feet per horsepower used in compression, whereas that of the low-pressure coils averaged between 0.6 and 0.7 square feet per 1,000 feet of gas and 3.5 square feet per horsepower. If the same amount of power is used by each cylinder of the compressor, there seems to be no reason why one cooling area should be larger than the other, unless the gas was not cooled in the low-stage coils to the temperature later obtained in the high-pressure coils.

The experience of A. W. Peake,[a] engineer in charge of gasoline production of the Mid West Oil Co., causes him to "believe that the coil area of the intercooler should be larger than the area of the aftercooler coils, as it permits condensation of more gasoline in the intercooler and reduces the chance of carrying condensate over into the high pressure cylinders, causing trouble by cutting the lubricating oil and thus wearing out the cylinders in a short time. This trouble has been experienced in quite a few plants. Increasing the intercooler area has been known to help overcome this, as also has been the placing of a steam or oil trap or some similar arrangement in the gas line, between low-pressure accumulators and high-pressure cylinder intake."

PERFECT COOLING.

Perfect cooling between low and high stage compression implies cooling the gas before it enters the high-pressure cylinder to the same temperature that it had on entering the low-stage unit. Such cooling is necessary if the two stages are to use the same amount of power in compressing equal quantities of gas an equal number of compressions. As shown in Table 3, the temperature of the gas

[a] Peake, A. W., Personal communication.

at the low-stage intake is usually higher than at the high-stage intake. Such a condition would, if the number of compressions were equal in each stage, cause an unbalancing of power in the high and the low pressure cylinders. In compression plants with imperfect cooling between stages the work in the cylinders is allowed to take care of itself in such a way that the number of compressions in the two stages is not exactly equal. As stated in previous paragraphs, it would be better practice to cool the gas at the plant intake to as low a temperature as practicable in water-cooled coils and to use the same temperature between compression stages and in the high-pressure coils. In general, to keep the gas at the lowest practicable temperature at all times during treatment is the best practice. From the high-pressure coils and accumulators the gas passes to the field fuel lines or, if expanded gas is used to reduce the temperature still lower, it is led to the high-pressure coils cooled by expanded gas.

USE OF EXPANDED GAS FOR COOLING.

TABLE 4.—*Data on cooling of gas by expansion at various plants.*

Plant No.	Discharge temperature of gas cooled in high-pressure coils.	Method of expansion.	Expansion unit discharge.			
			First stage.		Second stage.	
			Temperature.	Pressure.	Temperature.	Pressure.
	°*F.*		°*F.*	*Pounds.*	°*F.*	*Pounds.*
1		Expansion valve		25		
3		Drilling engine		10		
4	42	Expansion valve		10	(*a*)	(*a*)
6	−6 to −17	2-stage expansion engine		64	−40	10
7	20 to − 7	do		30		
9		do		30		5
10		1-stage expansion engine		30		15
11	10	do	−40	15		
12		do		12		
14	40	do	−20	25		
16	50	do		14		
17		do		(*b*)		
19	40	do	32	20		
20		do				
21		do	32	55		
30		Expansion valve				
32	65	2-stage expansion engine			−30	10
33	−30	do		60	−12	5
51		Expansion valve				
55		do				
76	38	1-stage expansion engine	2[illegible]			
77	40	do	37	10		
78	66	do	30			
79	60	Expansion valve				

a Changed to expansion engine. *b* Vacuum.

METHODS OF EXPANSION.

At many plants the gas after treatment in high-pressure water-cooled coils and accumulator tanks is further cooled, still at maximum pressure, in heat interchangers or double-pipe condensers by expanded gas. Two methods are used to obtain low temperatures

by the expansion of gas, (1) expanding the gas through a small opening or valve to a lower pressure, thus producing the absorption of heat, and (2) expanding the gas adiabatically in the power cylinders of a steam power unit, such as a compressor, pump, or drilling engine. Table 4 gives methods of expansion used at plants visited, also temperatures and pressures of the gas at the different stages of expansion and cooling.

EXPANSION THROUGH AN ORIFICE OR VALVE.

In the first method the high-pressure gas carrying some gasoline not removed by previous treatment is passed through either the inside or outside pipe of a double-pipe heat interchanger, and the dry gas is expanded through a small opening, such as a ½-inch valve, between the pipes, thus cooling the high-pressure gas and causing further condensation of gasoline. The high pressure gas and the condensate are led to an accumulator tank, where the condensate is collected and removed. From the accumulator tank the gas passes through the expansion valve of the heat exchanger and the pressure is lowered to 10 or 15 pounds, or the pressure desired or necessary to carry the gas through the field lines. The refrigerating effect obtained by this method is surprisingly small, and although many coils using this principle for cooling have been installed, few of them lower the temperature of the high-pressure gas enough to be of material benefit. In certain standard installations one coil of this type is installed with each high-pressure unit, the inside pipe of the coil having a diameter of 3 or 4 inches, and the outside 6 or 8 inches. The length is usually approximately 80 feet, and either the straight-line or return-bend type is used. After leaving this coil the gas is returned to the field for use on the lease, or sold to commercial gas companies.

COILS USED IN CONJUNCTION WITH EXPANSION ENGINES.

A study of Table 5 will give the reader an idea of the great variety of types and sizes of coils used as heat exchangers or refrigerators in conjunction with expansion engines and valve expanders. The principle is the same in all types. The cold expanded gas passes through one of the pipe members of a double pipe-interchanger while the high-pressure gas from the water-cooled coils passes through the other member. At the end of the coil in which the high-pressure gas is treated, an accumulator tank or drip collects the condensed vapor as in the water-cooled coils.

Of the plants listed in Table 5, No. 6 used the smallest size of pipe to form the double-pipe coil, 2-inch pipes inside of 3-inch.[a] The cooling effect in this coil is rapid, but a small quantity of moisture in the gas will tend to freeze the coil and stop the flow, necessitating

[a] The 1¼-inch in 2-inch coil mentioned in Table 5 as being part of plant 11 has been abandoned in favor of a larger double coil.

continual watchfulness and more or less thawing to do. This particular coil is protected to some extent from water vapor by first passing the gas through two other double coils, 4-inch pipe in 6-inch, which are cooled by the expanded gas from the small 2-inch in 3-inch coil. In the larger coils the gas is cooled only to such a temperature that the greater part of the liquid condensed is water. The cooling area varies between 0.15 square foot and 3.70 square feet per 1,000 cubic feet of gas treated, and averages 0.563 square foot.

TABLE 5.—*Data on double-pipe coils or heat exchangers used at various plants.*

Plant No.	Type of coil or exchanger.	Number of coils.	Size of pipe.			Length of single coil.	Total length of coil.	Radiating area.	
			Number of pipes.	Inside diameter.	Outside diameter.			Total.	Per 1,000 cubic feet of gas treated daily.
				Inches.	*Inches.*	*Feet.*	*Feet.*	*Sq. ft.*	*Sq. ft.*
1	Tubular	2	50	2	36	18	....	940	0.940
3	Straight line	1	1	8	16	80	80	167	.372
4	....do	2	1	8	12	60	120	250	.200
6	{Return bend	2	1	4	6	50	200	210	} .590
	{....do	120	1	2	3	20	2,400	1,257	
7	Special straight line	14	5	2½	12½	100	1,400	4,575	.610
9	Straight line	5	1	8	12½	100	500	1,050	1.05
10	Special	2	1	12½	24	40	80	262	.349
11	{Straight line	3	1	4	6	100	300	315	....
	{Return bend	96	1	1¼	2	20	1,920	630	.630
12	....do	6	1	4	6	80	480	502	.714
14	{....do	2	1	2½	5	80	160	105	} .272
	{........	2	1	4	6⅝	80	160	167	
16	Return bend	2	1	4	8	90	180	190	.750
17	....do	2	1	3	8	80	160	130	.173
19	Horizontal tubular	4	52	1½	30	16	832	326	.181
20	Vertical tubular	2	72	2	30	12	1,728	900	.600
21	....do	1	72	2	30	12	864	450	.450
30	Return bend	6	1	2	4	40	240	126	.168
32	....do	20	1	3	5	40	800	630	.210
33	....do	4	1	4	6	100	400	420	.233
51	....do	1	2	2	10	40	40	42	.170
55	....do	3	1	4	6⅝	80	240	189	.150
76	....do	12	1	4	8	40	480	500	.250
77	....do	4	1	4	8	40	160	167	.420
78	....do	4	1	4	8	40	160	167	3.70
79	....do	1	1	4	6	80	80	84	.330

From the 2-inch in 3-inch coil the sizes range through nearly all possible combinations up to 12½-inch inside of 24-inch. As the pipe sizes become larger, cooling is slower. The cooling effect in the last-mentioned coil is so sluggish that it is doubtful whether the coil can be considered efficient. The tubular type of heat interchangers, such as are used in plants 19, 20, and 21, either horizontal or vertical, are built in the form of a tubular boiler, the cold gas being either in the main drum shell or in the tubes. This type of interchanger has not been as satisfactory as some of the double-pipe coils.

It seems that the length of time and the necessary intimate contact between the gas and the tube surfaces is not obtained, and radiation is incomplete, the high-pressure gas being discharged at too high and the expanded gas at too low a temperature. Both the high pressure and the expanded gas is thought to follow channels through the drum

and tubes and form eddies or dead spaces, leaving some parts of the tubes and shell inactive. In this type of interchanger a series of baffles in both the tubes and shell might give the desired result, as has been done in refinery practice. This type of cooler is used at a number of plants as a water condenser and as a unit in conjunction with double-pipe coils of smaller size.

The coil used at plant 7 (see Table 5 and fig. 7) is of special straight-line construction, consisting of five $2\frac{1}{2}$-inch pipes inside of a $12\frac{1}{2}$-inch casing 100 feet long. This type of interchanger is not uncommon in refinery practice, being used for the interchange of heat between oil coming from and going to stills, but in the compression-plant industry its adaptation is unique. There are 14 units of this type in the entire battery. The high-pressure gas from the water-cooled coils is divided by a header and passes in parallel through the

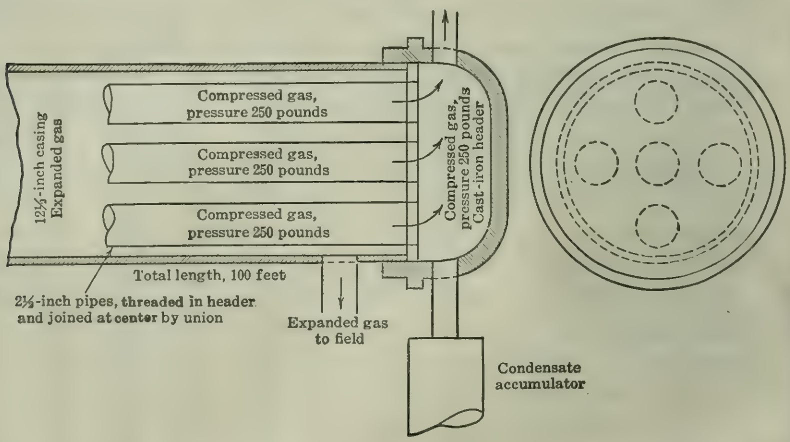


FIGURE 7.—Sections of special straight-line double coil.

$2\frac{1}{2}$-inch pipes of four of the units, at the end of which it is collected by a header, and again divided in the same way, passing in parallel through the $2\frac{1}{2}$-inch pipes of the remaining 10 units of the battery of 14. At the end of each unit a drip (see fig. 7) collects the condensate formed.

From the discharge header at the end of the group of 10 exchangers the gas goes directly to the expansion engine. The engine exhaust, or low-pressure cold gas, is returned to the 10 interchangers, passing through them in parallel in the $12\frac{1}{2}$-inch shell or outside pipe countercurrent to the high-pressure gas. After passing through the 10 units the gas is collected in one main or header and is again divided and passes in parallel through the outside casings of the other four units, again countercurrent to the high-pressure gas.

By using the 14 interchangers in two sets or batteries the gas is cooled in two stages, and by the counterflow system the coldest expanded gas is brought into contact with the coldest high-pressure

gas, thus making a gradual and complete interchange of heat. The expanded gas, on leaving the battery of four coils, has been raised to approximately the temperature of the high-pressure gas from the water-cooled coils, and the high-pressure gas traversing the inside pipes is brought to the lowest possible temperature by being circulated in contact with the coldest expanded gas after it has radiated a considerable portion of its heat to the partly warmed, expanded gas in the unit of four interchangers. Of the total plant production 10.4 per cent is credited to this system of cooling. These coils are not protected by a building, but are set well above the ground and housed in wooden boxes filled with sawdust, which covers the outer pipe fully 12 inches on all sides.

Plates VIII, *A*, and IX show views of the coils and expansion sets taken at a plant which the writer was fortunate enough to visit shortly after the installation of the expansion engine and before the cork insulation of the pipes had been completed.

INCREASE IN PRODUCTION DUE TO COOLING BY EXPANSION.

In Table 6 are recorded the percentages of total production and the gravities, in °B., of the fractions of condensate collected at the different stages in accumulator tanks in plants using expansion engines and keeping records of such data. The table shows that the percentage of condensate credited to expansion units varies between 10 and 50 per cent, except at plant 76, at which all of the condensate is collected in the accumulator tank after the cooling by expanded gas is completed. This case was cited before, and is undoubtedly due to the fact that the gas is forced to travel upward through the water-cooled coils, whereas the natural flow of any condensate formed would be downward. Apparently the condensate is absorbed by the gas and precipitated later in the double-pipe interchangers cooled by expanded gas.

TABLE 6.—*Percentages and gravities of condensate collected in various accumulator tanks in plants using expansion engines.*

Plant No.	Condensate produced from—					
	Low-pressure coil.		High-pressure coil.		Expansion coil.	
	Per cent.	Gravity, °B.	Per cent.	Gravity, °B.	Per cent.	Gravity, °B.
3	33	.....	60	79	7	95
4	15	.....	60	.....	25	.....
6	17.6	63.8	32.7	78	[a] 49.7	96
7	24.6	60	65	65	10.4	.....
9	26	60	42	80	22	90
11	.....	67	.....	84	.....	93
17	30	57	50	71	20	80
32	.....	.....	.....	.....	10–15	95
33	40	70	35	80	25	100
76	.....	.....	.....	.....	[a] 100	76–82

[a] No condensate in water-cooled coils.

FIELDS IN WHICH EXPANSION UNITS ARE USED.

In the eastern fields, where much of the gas treated contains little or no fixed or true gases, being almost entirely composed of vapors of the higher hydrocarbons, the use of extremely low temperatures is of little or no benefit, and expansion engines and coils have not, in any plant known to the writer, been installed.

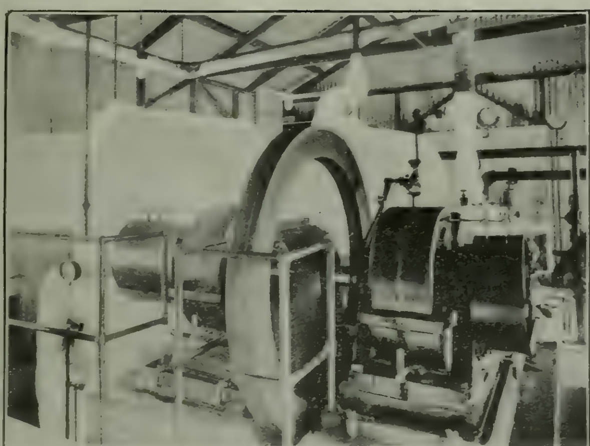
Mid-Continent practice, taken as a whole, does not include expansion engines as a part of the usual installation; expansion sets are, however, being adopted by some operators building new plants at the present time as a part of the original plant design. Two plants (Nos. 32 and 33) visited by the writer in Oklahoma had expansion engines and coils in service, both being in the Glenn pool. The operators of these plants stated that of the total production 10 to 25 per cent was directly due to cooling by gas expanded in engine cylinders, as shown in Table 6. The cooling area of the double-pipe heat interchangers used in the two plants averages 0.22 square foot per 1,000 cubic feet of gas treated, which is less than one-half the average area used in California practice.

In the Caddo, Louisiana, field one company operating three compression plants uses expansion units and coils in each plant.

EXPANSION ENGINES IN CALIFORNIA FIELDS.

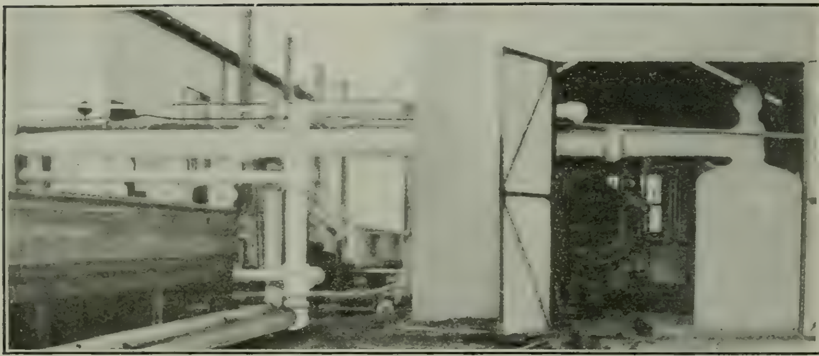
The widest range of development in the installation of heat interchangers and the use of expansion engines is in California practice. At plants 3, 4, 6, 7, 9, 11, and 17 in the various California fields, 7 to 50 per cent of the total production is from expansion units, as shown in Table 6. It is generally figured in these fields that 25 per cent of the production is due to the expansion treatment. A plant in the Fullerton field treating 2,500,000 cubic feet of gas daily produced 3,000 to 3,200 gallons of condensate with a gravity of 72° B. before the expansion unit was put into operation. The expansion unit increased the daily production to between 4,000 and 4,300 gallons of condensate with a gravity of 80° to 84° B., or about 25 per cent of the total yield. The radiating areas in the heat exchangers used in California plants (see Table 6, plants 1 to 21) vary from 0.20 to 1.05 square feet per 1,000 cubic feet of gas treated daily. A radiating area large enough to warm the cold or expanded gas to the temperature, as nearly as practicable, of the high-pressure gas from the water-cooled coils is all that is necessary, because any further increase in cooling surface, the two gases being brought to approximately the same temperature, has no effect. The proper area for each 1,000 cubic feet of gas to be treated daily is a factor that can be obtained only by experiment at each plant, unless the designer has had experience in the particular field and with the particular gas

A. END OF HORIZONTAL TUBULAR COOLER, TYPE USED IN PLANTS 19, 20, AND 21.

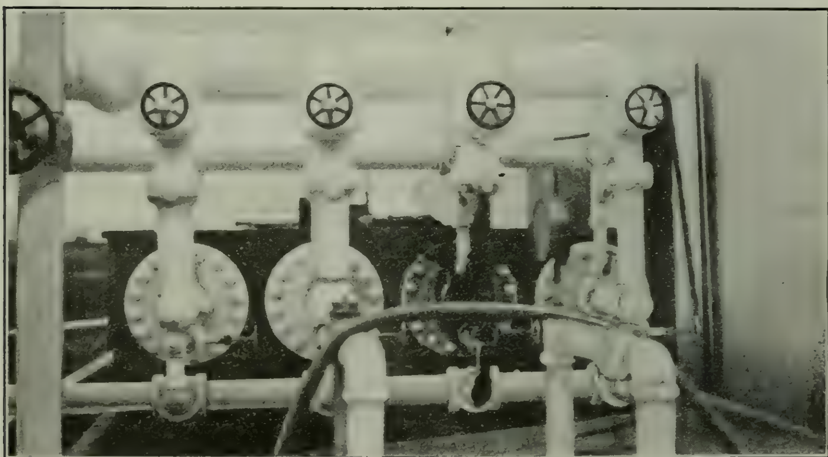


B. TWO-STAGE EXPANSION ENGINE IN COMPRESSION PLANT.

Note ice on accumulator tank and piping.



A. EXPANSION-EXHAUST ACCUMULATOR TANK AND PIPING. TANKS SHOW 2-INCH COATING OF FROST. TEMPERATURE OF GAS WAS BELOW 0° F.



B. END OF DOUBLE-PIPE COILS AND INTAKE MANIFOLD FOR EXPANDED GAS.

C. HEADER FOR EXPANDED GAS. CORK INSULATED INTAKE, PIPES EXPOSED TO AIR.

to be treated, or has data on the area used and the efficiency obtained at another plant already at work in the same field and treating the same gas.

TEMPERATURES OBTAINED FROM GAS EXPANSION.

The temperatures produced by heat exchange on high-pressure gas vary in practice from $-17°$ to $+65°$ F., or between 75° below and 20° F. below atmospheric temperature, as shown in Table 4 (p. 41). The best temperature to use in a given plant depends, as does the ultimate high pressure used, on the characteristics of the gas and the product desired, also on the efficiency of extraction and temperature previously obtained in the water-cooled coils. As the condensation of vapors depends on both temperature and pressure, in accordance with the physical laws of gases, at a given pressure there is some critical temperature below which it is useless to cool the gas, as Burrell[a] has demonstrated in the laboratory method of determining the quantity of condensable vapors in any given gas. The method of laboratory test uses only atmospheric (14.4 pounds at an elevation of 600 feet) pressure, and the extremely low temperature of 115° C. below zero, which is equal to 175° F. below zero.

At this temperature all of the propane and the butane are liquefied, which in compression practice is neither practicable nor desirable, because these two hydrocarbons are so volatile at atmospheric temperatures and pressures as cause them to weather out of plant products to a large extent, if not entirely. As a portion of each condensable hydrocarbon is precipitated and taken out of the gas, the pressure necessary to condense the remaining portion at a constant temperature rises, in accordance with the law of partial pressures. Or, with the pressure remaining constant, the temperature must be reduced to precipitate the remaining portion of that particular vapor fraction. Conversely, if at a given pressure any condensable constituent would be entirely precipitated when the gas reached the critical temperature of that fraction, the composition of the gas would be simplified and the precipitation of the other condensable fractions more complete at the same pressure. This has been demonstrated in practice in a plant using a maximum pressure of 250 pounds, and a temperature as low as 10° F. below zero at the discharge of the high-pressure coil, which was cooled by expanded gas. (See Pl. IX, *A*.) The condensate collected in the tank at the end of the coil contained more than 1 per cent of water; a small percentage of water was also found with the lightest condensate precipitated at the exhaust of the second stage of the expansion engine. (See Pl. VIII, *B*.) If water vapor is retained through all of the steps of compression and

[a] Burrell, G. A., and Jones, G. W., Methods of testing natural gas for gasoline content: Tech. Paper, 87, Bureau of Mines, 1916, p. 26.

cooling, as demonstrated in the plant just cited, it is probable that portions of all the hydrocarbon fractions are also. The points to be determined in any plant are the quantity of such vapors being lost and the temperature necessary to condense them as well as the value of the product and the cost of an installation to obtain the required results.

The value of the condensate obtained will depend on the quantity that can be marketed, and if excessive pressures are used, the product may be so light and volatile as to be of little value. A proper relation between pressure and temperature will in all instances yield the maximum marketable condensate from any given gas, and this relation can be found only by trials and tests made at each plant. In the plant cited above, the product obtained in the accumulator at the expansion engine exhaust had a gravity of 105° B., and probably consisted principally of butane, with small proportions of the other higher hydrocarbons and of water. The gas in this accumulator had a temperature of 40° F. below zero and a pressure of 10 pounds, as the result of the two stages of expansion. It was found that in the expansion cylinder of the engine, the gas had reached a temperature lower than 100° F. below zero before being exhausted. The quick rise in the temperature of the gas between the cylinder and the tank, which was connected to the exhaust by a short insulated pipe, is probably due to two factors, radiation from the cylinder walls and the latent heat of vapors given out on condensation.

In a plant in Oklahoma, in experimenting with expansion units, it was found that the desired low temperatures could not be obtained. So little vapor was precipitated in the coils ahead of the expansion unit that in expanding the gas the latent heat given up by the condensing vapors immediately reheated the expanding gas to 20° F. The remedy for a condition of this kind would necessarily have to be found either in the pressure or water cooling to which the gas was being subjected.

TEMPERATURE AND PRESSURE CHANGES IN A COMPRESSION PLANT.

Figure 8 shows diagramatically the changes in both pressure and temperature to which gas is subjected in average compression-plant practice. The vertical coordinates show temperatures in degrees Fahrenheit for the solid line or temperature curve, and pressures in pounds per square inch for the dotted or pressure curve. The horizontal coordinates represent the different stages of treatment at which the changes of pressure and temperature occur.

FLOW SHEET OF A COMPRESSION PLANT.

Figure 9 shows the gas flow diagram of a 2-stage compression plant using single-stage expansion, connected with two sets of expanded-gas cooled coils in series. The gas intakes and discharges of the com-

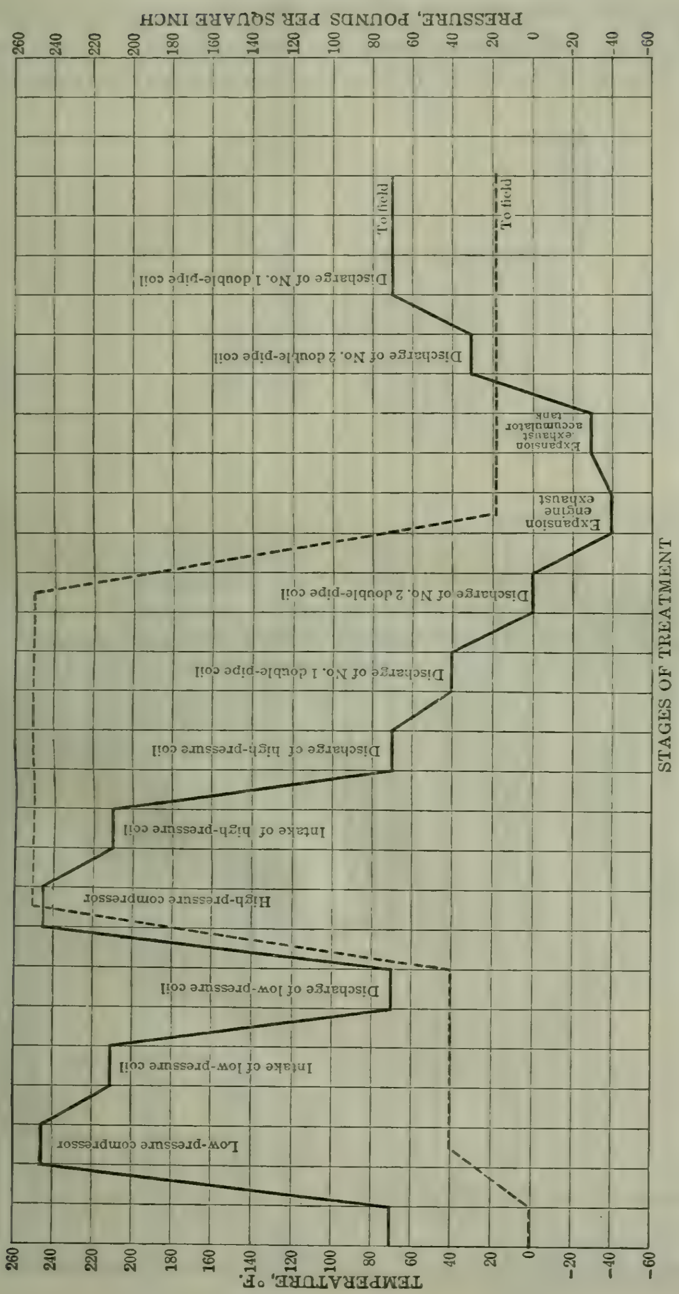


FIGURE 8.—Diagram showing the changes in temperature and pressure of gas in compression-plant practice. Dotted line is pressure curve, solid line is temperature curve.

pressors and the water-cooled coils are shown connected in manifold, this system of connections being the most flexible. With valves properly placed, any unit, part of a unit, or coil may be cut out for

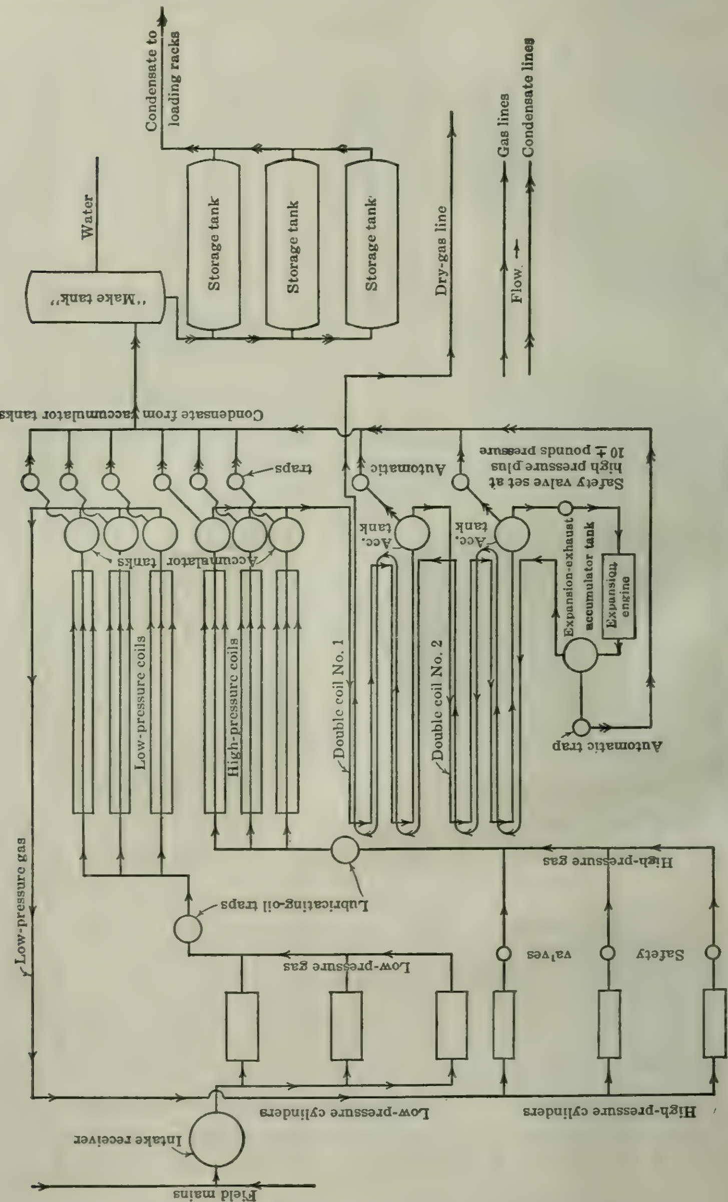
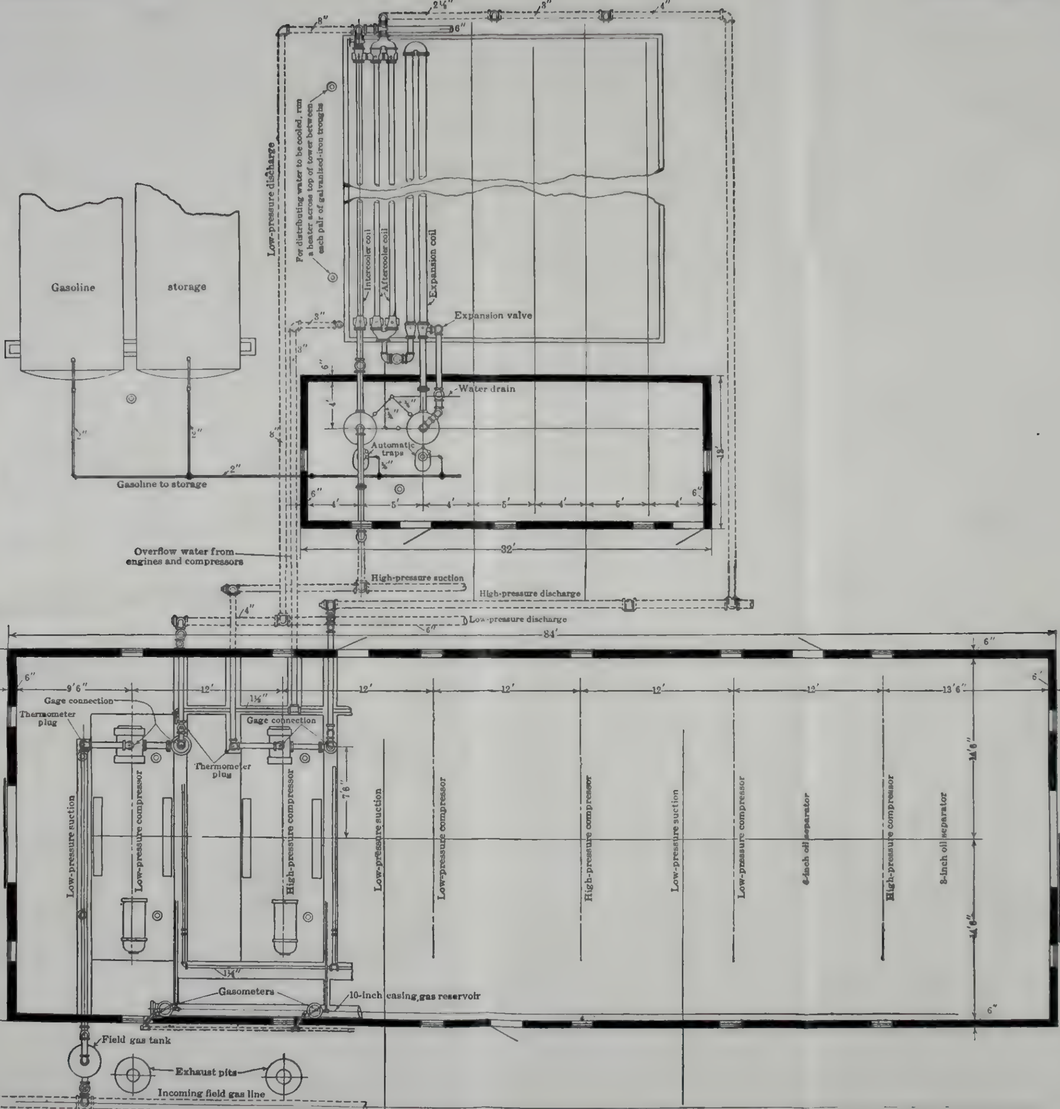
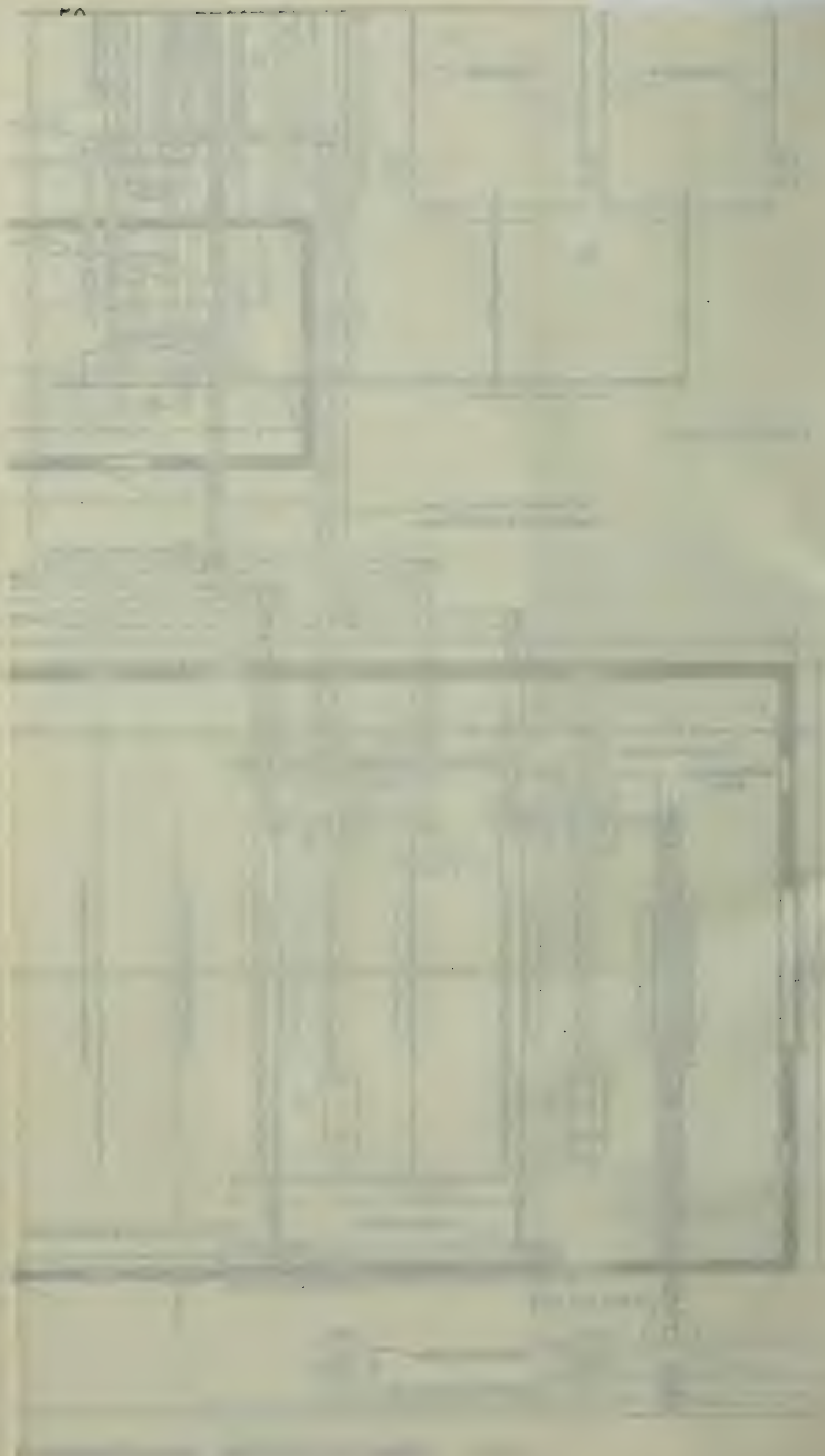


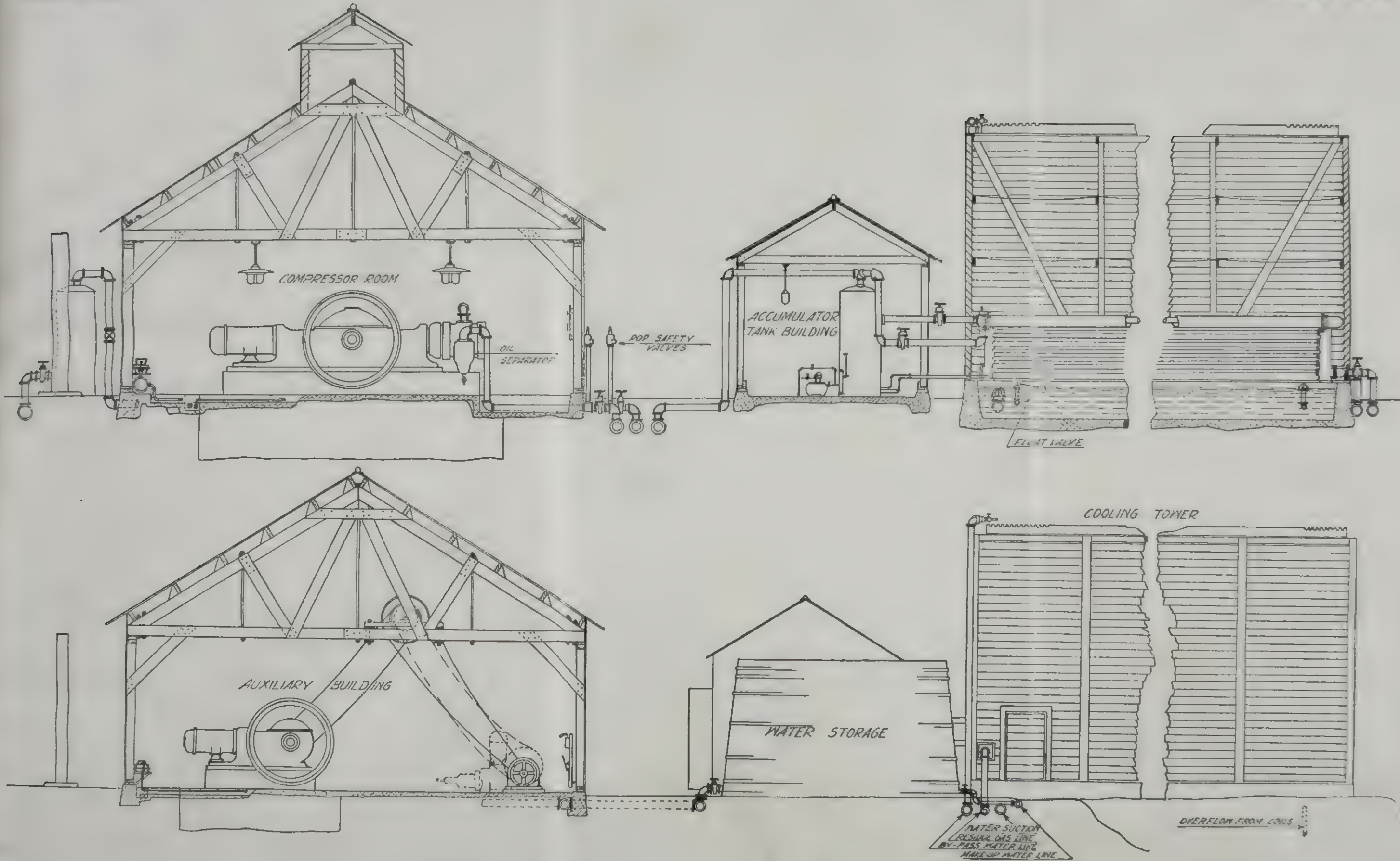
FIGURE 9.—Flow sheet of compression plant using 2-stage compression and single-stage expansion.

inspection or repairs without shutting down any other part or stopping plant operations, the work of the inactive unit being taken up by a small overload on the other units.



PLAN OF TYPICAL DIRECT-CONNECTED COMPRESSOR PLANT, COILS, AND TOWER.





ELEVATION OF COMPRESSOR, AUXILIARY BUILDINGS, AND COOLING TOWER OF PLANT SHOWN IN PLATE X.

A single-stage expansion engine is shown connected with two double-pipe coils in series; if two stages of expansion were being used each of the double-pipe coils would use the gas expanded in one stage and be so connected that the gas from coil No. 1, using first-stage expanded gas, would return to the second-stage expansion cylinder, from which it would be returned to coil No. 2 to further cool the high-pressure gas.

Plates X and XI show plans and elevations of a typical direct-connected compressor plant. The low-pressure and the high-pressure cylinders are operated independently by separate gas engines.

USE OF POWER DEVELOPED BY GAS EXPANSION.

At all plants where expansion units are used, the development of power by the expansion of the gas has been a secondary consideration. In a number of plants power is developed only to give resistance to the expanding gas, as in a plant using a pump under a back pressure of 150 pounds, and in another plant compressing air to 40-pound pressure, only to release it to the atmosphere through a small valve set to hold the required back pressure on the natural gas.

In plant 17 the compressor end of the expansion unit holds a vacuum on the double-pipe coil and on the exhaust of the power cylinder, and delivers the gas at a pressure sufficient to return it to the lease. (See Pl. XII, *A*.) This use of the power developed is not uncommon, although usually the compressor suction is above atmospheric pressure. At plant 76 the power developed from expanding the gas in two single-stage cylinders working in duplex is used to compress air in two stages to a pressure of 85 pounds, to be used in air lifts in pumping oil wells. Other plants use the power generated by single-stage expansion units, as in the tandem compressor, or by two-stage expansion units, as in the cross-compound machines, to drive one of the two-stage compressor units connected in parallel with the other compression cylinders, both at the intake and the discharge. A compressor used in this way may, as at plants 6 and 14, take gas from and deliver it to the manifolds used for the intake and discharge of the other compression units.

EFFICIENCY OF EXPANSION UNITS.

The amount of power developed in an expansion engine as compared with the amount used in compression is very low, probably not more than 5 or 10 per cent in average plants. This condition is to be expected because of the energy loss through dissipation of heat, the consumption of power in operating the piston and valve in the expansion cylinder, and the reduction in pressure through losses of gas and vapor by condensation and leakage during transmission through pipes and cooling systems.

An exceptional instance of power developed in an expansion unit was noted at a California plant. Tests showed that between 25 and 35 per cent of the power used to compress the gas was developed by the expansion engine, which used in its power cylinders all of the gas compressed in two stages of expansion, with heating between the two expansion cylinders. The plant compressed 1,900 cubic feet of gas per minute, of which 690 cubic feet was compressed in the compressor end of the expansion engine.

The gas entering the high-pressure cylinder of the expansion engine at a pressure of 250 pounds had a temperature of 5° F. below zero; the discharge pressure was 50 pounds. The gas was then passed through double-pipe coils and heated to 50° F. before it entered the low-pressure power cylinder. From this cylinder it was exhausted at a pressure of 10 pounds and a temperature of 40° F. below zero. The gas from the second expansion exhaust was used for cooling the high-pressure gas, and was then discharged from the plant at 57° F. A measurement of the temperature in the low-pressure expansion cylinder indicated a temperature of 140° F. below zero.

If a more efficient return of power were made an object, more power could be developed by heating the high-pressure gas, after it leaves the double-pipe interchanger, in an interchanger with the hot gas from the high and the low pressure compression cylinders. If desirable the gas could be further heated in a double-pipe interchanger by the exhaust from the power cylinder of the gas engine, or in a tubular interchanger such as is used for preheating boiler water with exhaust gases.

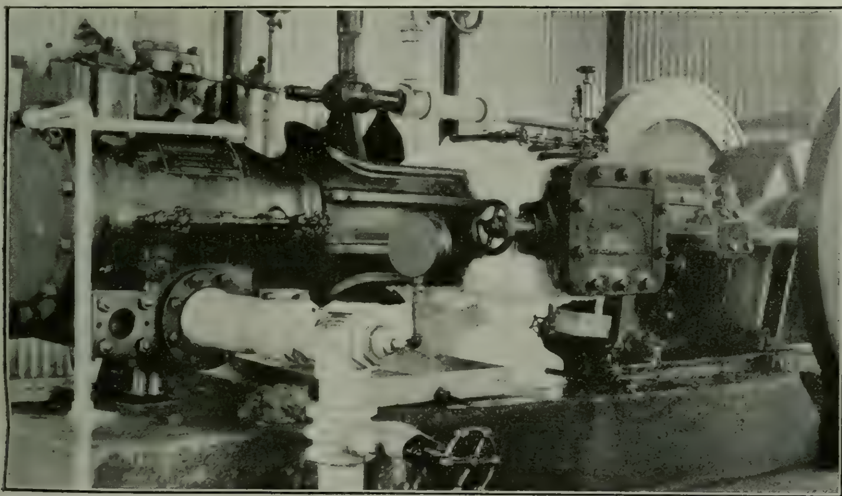
Heating the compressed gas before it enters the valve chest of the expansion cylinder would also tend to reduce freezing at that point, thus reducing the power used in moving the valve mechanism.

To obtain as low temperatures of the expanded gas, with preheating as without preheating, more power would have to be developed and used by the expansion unit. This could be accomplished by added expansion units, by increasing the load, or by running the compressor faster at the same pressure, thus increasing the total volume of gas compressed in a given unit of time.

EXPANSION FOR POWER ALONE.

In expanding compressed gas for power purposes only, and not for refrigeration, as is contemplated in an eastern plant, preheating the gases by either the hot compressed gas or the engine exhaust would be necessary in order to make the installation a commercial success. Using a relatively small quantity of gas at a low temperature (60° F.) would hardly pay in power delivered, as compared with a gas engine using gas worth 15 cents or less per 1,000 cubic feet.

A. LOADING RACK FOR TANK CARS AT BLENDING STATION.



B. SINGLE-STAGE COMPRESSOR USED AS EXPANSION ENGINE PUMPING GAS TO FIELD AT 60 POUNDS PRESSURE.

C. COMPRESSION PLANT, SHOWING HORIZONTAL TYPE OF "MAKE" TANKS IN MIDDLE FOREGROUND, AND OF ACCUMULATOR TANKS, AT RIGHT.

USES MADE OF TREATED GAS.

With the passage of the gas through the coils of the expansion unit, the treatment for recovery of gasoline is finished.

Gas used for power to run the compression plant, either in gas engines or under boilers, is universally taken from the treated gas, the rest being returned to the lease or pumped into the lines of a commercial gas company. The lease or contract usually stipulates that gas used for power in the compression plant is to be taken from the treated gas at no cost to the lessee.

GAS USED PER HORSEPOWER IN COMPRESSION UNITS.

The quantity of gas necessary to operate a gas engine will vary from 9 to 18 cubic feet per horsepower-hour, depending on the size, type, and age of the engine and the care given it. Boilers in a steam plant require 40 to 120 feet per horsepower hour. A plant having six 80-horsepower, direct-connected, horizontal, 2-cycle gas engines used between 12 and 14 feet. The engines had been in service two years and had been well cared for. The large 450 to 1,100 horsepower, horizontal, direct-connected, tandem, double-acting, 4-cycle units will use as little as 9 feet and the 150 to 200 horsepower, vertical, 4-cylinder, 4-cycle, belted units will use 10 to 14 feet per horsepower hour.

Oliphant[a] gives the following table showing the average amount of natural gas required to operate gas engines or to supply a steam-engine plant using natural gas as fuel under the boilers in cubic feet per indicated horsepower hour:

Cubic feet of natural gas required per horsepower-hour to drive a gas engine or steam plant.

	Cu. ft.
Large gas engine, highest type	9
Ordinary gas engine	13
Triple-expansion condensing steam engine	16
Double-expansion condensing steam engine	20
Single-cylinder steam engine with cut-off	40
Ordinary high-pressure steam engine without cut-off	80
Ordinary oil-well pumping steam engine	130

From 10 to 12 cubic feet of air is necessary for the complete combustion of 1 cubic foot of natural gas.

PERCENTAGE OF GAS RETURNED AFTER CONDENSATE AND GAS USED FOR POWER IS DEDUCTED.

The reduction in the volume of the gas from treatment by the compression process is unaccountably large. As has been stated, in treating gas from old wells that have been gas-pumped for years and are held at high vacuums, practically all of the gas disappears in one stage or another of the treatment, often not enough being left to run the engines.

[a] Oliphant, F. H., Catalogue of metric metal works, 1914, p. 42.

Gas produced under natural pressure in the newer fields contained a much higher percentage of fixed gases, hence the quantity of residual gas, after condensate and gas used for power have been deducted, reaches 70, or, in some plants, it is claimed, 80 per cent of the total wet gas entering the plant. Exact figures on the quantities of residual gas are seldom kept in compression plants, it being a matter of little importance in most fields. It appears, however, from the figures that the writer was able to obtain that in plants treating gas yielding 1½ to 2 gallons of condensate per 1,000 cubic feet the net amount of gas left after treatment and deducting gas used as fuel, would average approximately 66 per cent of the total amount entering the plant. As the gas being treated increased in gasoline content the quantity of residual gas became less and less until it was not sufficient to furnish power for compression.

GAS USED FOR POWER AND TO FORM CONDENSATE.

Between 10 and 15 per cent of the total quantity of gas treated is required for power purposes, depending on the type and the efficiency of the engines driving the compressors. Burrell[a] states that it takes, on an average, 35 cubic feet of vapor to produce 1 gallon of condensate, or 3.5 per cent for each gallon produced from 1,000 cubic feet of gas, or if 3 gallons of unweathered product is made it will account for 10.5 per cent of the total gas entering the plant. The condensation of water vapor during the treatment will also account for a certain percentage of the total volume. The gas and vapor unaccounted for in the ways noted must be lost by leakage in pipes and machines during the various stages of plant operation, and by weathering of light fractions.

FOREIGN CONSTITUENTS IN NATURAL GAS.

AIR.

Besides water vapor, a number of gases not of the hydrocarbon groups are often found in natural gas. Air, if present, may be a constituent of gas from wells under high vacuums, but is usually due to inward leakage, either in the well casing or in lines transmitting the gas to the plant. At a plant visited in the Shallow pool of Oklahoma, the writer was informed that the gas being treated contained 30 per cent air. The area from which the gas was being drawn covered 12 square miles, making the use of long gathering lines and many vacuum pumps necessary, which probably accounts for the extremely high air content.

[a] Burrell, G. A., Seibert, F. M., and Oberfell, G. G., The condensation of gasoline from natural gas: Bull. 88, Bureau of Mines, 1915, p. 60.

WATER VAPOR.

Air always carries more or less water vapor with it, and this fact may account for part of the water precipitated with condensate. As most oils carry some water with them from the oil-bearing formations, it is natural to believe that some water vapor from this source would be carried into the gas, especially when the wells are being gas-pumped and low pressures maintained. The temperature of the oil and water under ground would also tend to allow water vapor to form and be held in the gas. In one instance, the oil coming from a certain well also producing gas had a temperature of 150° F. in the flow lines.

A California plant treating 2,500,000 cubic feet of gas daily produced water with the condensate at various points as follows:

Gallons of water drained from various points at California plant in 24 hours.

	Gallons.
From low-pressure accumulator	200
From high-pressure accumulator	50
From final double-pipe coil	25
From storage tank	65
Total	340

This quantity of water was equal to between 5 and 6 per cent of the condensate produced.

CARBON DIOXIDE.

The proportion of carbon dioxide in natural gas used in compression plants varies widely. As much as 30 per cent has been found in both the Mid-Continent and California fields. So large a proportion is unusual, but percentages up to 10 are not uncommon in California fields, and in some districts in Oklahoma.

Nitrogen is found in the natural gas in some districts, as noted by Burrell,[a] but was not found in gas fields visited and sampled by the writer, except as introduced into the gas with air.

SULPHUR COMPOUNDS.

Hydrogen sulphide or other gaseous sulphur compounds, usually called "sulphur gas," is found in many of the fields producing casinghead gas. However, only the gas from small areas of these fields contains sulphur in such quantities as to be a decidedly detrimental factor in treatment of gas for its gasoline content.

Plants in the southern Illinois field are troubled by sulphur compounds more generally than those in any other district as a whole. A plant in the Santa Maria and one in the Salt Lake field in California report sulphur trouble, but such contamination is local and is not characteristic of those fields as a whole.

[a] Burrell, G. A., Seibert, F. M., and Oberfell, G. G., The condensation of gasoline from natural gas; Bull. 88, Bureau of Mines, 1915, pp. 21–22.

GENERAL EFFECTS ON COMPRESSION TREATMENT.

The gases named, with the exception of hydrogen sulphide, are inert chemically through all the stages of the compression process. Physically they affect plant practice in two ways. They cut down the volume of productive gas treated or absorb power for which no return is possible; they complicate the problem of partial pressures by requiring higher pressures for the gas as a whole in order to bring any one of the condensable fractions to its critical pressure, thus again necessitating more power.

EFFECTS OF SULPHUR AND METHODS OF REMOVAL.

In the Lawrenceville district of southern Illinois the proportion of sulphur in the natural gas is so large as to be a decided detriment to treatment by compression. Beside destroying the pipes in cooling coils, so much of the hydrogen sulphide is dissolved in the condensate, either as a gas or as a liquid, that resort is had to steam distilling in order to free the condensate from this objectionable content. The odor of even small proportions is noticeable, making the product unsalable, and such gasoline, if used in motors, will attack the pistons and cylinders, causing pitting and roughness. By use of the steam stills in that district between one-third and one-half of the total plant product is lost as noncondensable vapor passing through the cooling coils after the stills.

The two California plants, mentioned previously, report no trouble with sulphur in the condensate, but do have trouble from the sulphur gas attacking and eating out cooling coils. At the plant in the Salt Lake field 2-inch steel pipes will often be eaten through, particularly at a low point in the coil, in 3 or 4 months. The plant in the Santa Maria field found that 2-inch steel pipe, costing 12 cents per foot (May, 1916), in the cooling towers lasted 6 months, and that wrought-iron pipes, costing 19 cents per foot at that time, lasted 13 months or more.

No compressor or engine trouble traceable to hydrogen sulphide gas was reported at any of the above plants, possibly because of the film of lubricating oil constantly protecting the pistons and cylinders.

The elimination of sulphur gas has long been a part of the treatment for purifying manufactured or artificial gas. The artificial gas made from coal or oil is passed through a scrubber containing iron oxide (common hematite iron ore). A chemical reaction takes place, the sulphur uniting with the iron to form iron sulphide, which is a solid at normal temperatures, thus removing the sulphur from the gas. When the iron becomes slow in its action, or so largely converted to the sulphide as to be inefficient in removing the sulphur, it is discharged and a fresh charge placed in the scrubber. The scrubbers are generally operated in pairs to allow one to be cut out

during periods of cleaning and charging. The discharged iron ore is thrown out on the ground, where it is oxidized by the action of the sun and the atmosphere, and again used as a fresh charge for the scrubbers.

The sulphur compounds originating in gas act chemically as an acid in much the same way as the acid fumes that are carried in still vapors in oil refining.

An eastern refinery which compresses the uncondensed still vapors and gases to further remove condensable fractions uses a series of water and caustic washes in scrubbing tanks to remove acid impurities, as described on page 68.

To overcome the action of sulphur gas which was eating out the high-pressure coils of a compression plant, Mr. D. L. Newton, general superintendent of the Hurley Smith Gasoline Co., of Los Angeles, Cal., designed and successfully operated a scrubber and cooler combined which removed the objectionable gases and also took the place of the high-pressure water-cooled coils.

Figure 10 shows the general design and method of operation of the scrubber. After this treatment the gas was refrigerated in double-pipe coils of usual construction without causing their destruction or forming incrustations of sulphur compounds.

The following data, regarding the operation of the scrubber, was also kindly furnished by Mr. Newton:

Data on scrubber for removing sulphur.

Capacity, 300,000 cubic feet per day at a pressure of 250 pounds.
Temperature of gas entering scrubber, 190° F.
Temperature of gas leaving scrubber, 78° F.
Temperature of water entering scrubber, 72° F.
Temperature of water leaving scrubber, 78° F.
Volume of water used per 24 hours, 15,000 gallons.

The water used in the scrubber, after being automatically trapped from the separator, was returned to the top of the cooling tower for cooling in the usual way. Owing to aeration and the lowered pressure, the greater part of the sulphur gas passed off into the air, the cooled water being returned to the scrubber by a pump at a pressure slightly higher than that at which the gas entered the scrubber.

CONDENSATE.

LINE DRIP.

The first condensate produced in treating gas by compression is the small quantity of rather heavy and often discolored naphtha accumulating in the pipe-line drips. After this condensate has been collected and cleaned by filtering or distilling it is mixed with the balance of the plant product, giving the mixture a lower gravity and vapor tension and helping to stabilize the "wild" condensate from other parts of the plant.

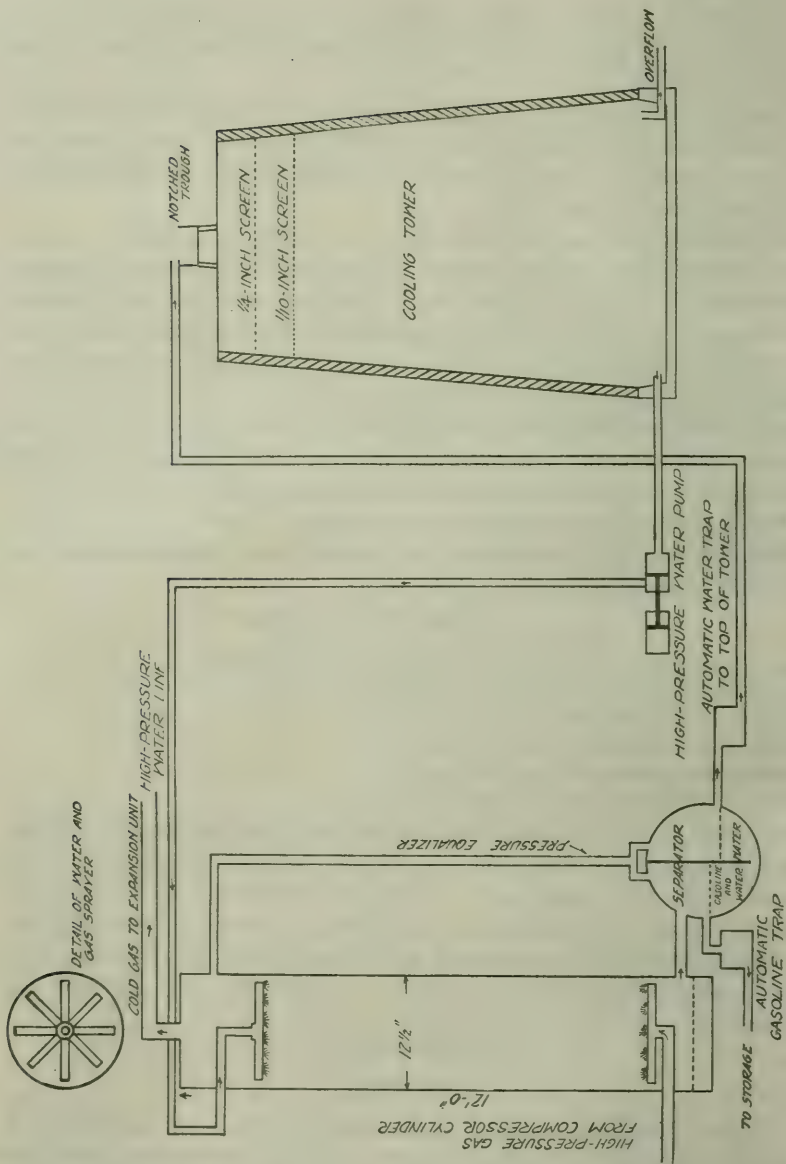


FIGURE 10.—Scrubber used to cool gas and remove sulphur compounds.

CONDENSATE FROM LOW-PRESSURE COILS.

The second condensate is that collected in the low-pressure accumulator tanks; its proportion to the whole product varies between nothing and 50 per cent, and in average plant practice between 10 and 30 per cent. The gravity varies around 60° B. and the vapor tension between 1 and 3 pounds. Such condensate makes an ideal motor fuel just as it comes from the coils, but is usually mixed before leaving the plant with the other products either in "make tanks" or in storage tanks, having the same tendency as the line drip to improve the product as a whole.

The following distillation represents approximately an average first-stage condensate as produced in California practice:

Results of fractional distillation of first-compression naphtha (condensate).

[Analyst, Paul W. Prutzman.]

Still charged with 500 c. c., at 62° B.; started over at 106° F.

Cut No.	Amount of cut.	Final temperature.	Gravity of cut.	Per cent.
	c. c.	*°F.*	*°B.*	
1	50	174	76.8	10
2	50	192	71.8	10
3	50	206	66.5	10
4	50	218	63.1	10
5	50	228	60.8	10
6	50	241	58.4	10
7	50	254	56.5	10
8	50	272	54.6	10
9	50	312	51.4	10
....	16	352	....	....

Total amount distilled off and collected, 466 c. c.; final temperature, 352° F. Loss, 8 per cent.

Eastern or Mid-Continent products with these end points would have a specific gravity between 5° and 9° B. higher, but the sample distilled is fairly representative of the first-stage product of two-stage plants.

CONDENSATE FROM HIGH-PRESSURE COILS.

Next in the series of condensates collected is that obtained from the gas under the maximum pressure used in any given plant and at temperatures developed by water cooling.

In average plant practice the condensate precipitated and collected at this point represents the principal bulk of the total recovery, seldom being less than 30 per cent of the total product even in plants using expansion units, and at times reaching 100 per cent, as in all single-stage practice and in some two-stage installations. At plant 22, which compressed the gas to 300 pounds in two stages and cooled it to 60° F. in the high-pressure coils, all the condensate was produced at this point, the product having a gravity of 96° B.

The specific gravity of the high-stage condensate is between 65° B. and 100° B., averaging in eastern fields approximately 85° B., in Oklahoma 78° B., and in California 72° B.

As formed in the accumulator tank this condensate is "wild," owing to the absence of low-gravity fractions, to dissolved gas, and to hydrocarbons that can be held as liquids only under high pressure at the temperatures attained in the water-cooled coils. As the pressure is reduced by the automatic traps or in the transfer from accumulators to the "make" or storage tanks, the lighter fractions and dissolved gases immediately start coming off and build up pressure in the tank containing them or escape to the atmosphere. For these reasons the condensate from high-pressure accumulators is usually discharged to tanks containing the heavier fractions precipitated in other coils and is often blended in there, or before it reaches the storage tanks.

CONDENSATE FROM EXPANSION COIL.

Table 6 (p. 45) gives the gravity and percentage of this condensate as obtained in plants using expansion units. The condensate has much the same physical characteristics as the condensate from high-pressure water-cooled coils and is handled and treated in the same way.

CONDENSATE FROM EXPANSION EXHAUST.

As stated and discussed under expansion units, plant 6 collects a high-gravity (105° B.) condensate in an accumulator close-connected to the exhaust of the second-stage expansion cylinder. This condensate is stored separately and held under pressure until blended with large quantities of 48° B. naphtha.

At the plant shown in Plates VIII, *A* (p. 46), and IX, *A* (p. 47), the condensate collected in the expansion-exhaust accumulator tank is mixed with the balance of the plant product and the mixture is shipped, without blending, by auto trucks.

CONDENSABLE HYDROCARBON FRACTIONS IN NATURAL GAS.

From these data and from points previously brought out, it appears that different natural gas from different fields containing the same quantity of condensable vapors seldom contains the same percentages of the various hydrocarbon fractions entering into the composition of gasoline.

This, in part at least, explains the wide variation in the gravity and amount of product obtained under similar conditions of temperature and pressure in different plants treating gas from different parts of the same field or from different fields.

From the study made by the writer of the conditions as found in fields throughout the United States, the explanation seems to lie in

any one, or a combination, of three conditions—the fractional composition of the gasoline content of the oil from which the gas comes, the temperature of the oil, and the pressure on the oil at the time of releasing the vapors to the gas.

Under the first condition, as demonstrated by refinery results and fractionations, it has been shown that distillates of the same gravity and the same or different end points vary widely in the content of the different fractions obtained between the same temperature limits. The oil containing only certain fractions of the light hydrocarbons can give up only these fractions to the gas, regardless of the temperature or pressure.

As the temperature of the oil varies in different fields and at different localities and depths in the same field, the factor of temperature must bear directly on the fractions of distillates contained in the gas. At constant pressures and temperatures only certain of the fractions will vaporize and be carried into the gas, leaving other fractions as liquids with the oil.

In any oil field, rock pressures decline as the supply of gas and oil is reduced. As the boiling or vaporizing temperatures of liquids are lowered by reduced pressures, this condition of lower pressures allows the less volatile, heavier fractions to vaporize if the temperature remains constant, thus adding to the gasoline content of the gas. As the rock pressure becomes low and the rate of decline so slow as to be practically stationary, and vapors no longer distill naturally from the oil left in the ground, resort is had to vacuum pumps to increase the flow of oil and gas, thus permitting the vapors to distill from the oil in the sands. Under this method is produced the gas of which the greatest proportion is condensable, as in eastern compression practice.

The widely varying conditions under which casing-head gas obtains its charge of condensable vapors, the variable content of lighter hydrocarbons in the oil in the ground, and the direct effects of the law of partial pressures on the products precipitated at the different stages in plant practice will to no small extent account for the great differences in plant practice as to pressures and temperatures used, and also for the variations in the percentage and gravity of the condensates of successive plant stages and the gravity and vapor tensions of the product of plants in different fields.

VARIATIONS IN PLANT PRODUCT.

The quantity and the gravity of condensates from different plants is shown in Table 2 (p. 29). These figures represent the average quantity and the average gravity, but both vary considerably from day to day and month to month. Many theories have been advanced to account for these variations, but none of them is satisfactory in analyzing the variations as they actually occur in plant production.

From the known effects of temperature on gas containing condensable vapors, it is reasonable to believe that atmospheric conditions, changing as they do with the seasons, explain in part the differences noticed from time to time in the yields from the different stages and in the total plant output. Many operators state that a larger proportion of condensate of higher gravity is collected in the low-stage accumulator tanks in cold weather. This same result is noticed also in the quantity and gravity of "line distillate" precipitated in gathering systems and collected in the line drips. In many plants the total production increases in winter, but this is not always true, as in plants using low temperatures, produced by expansion engines. It is often found that cold weather condenses some vapor in the gathering lines, and unless this is collected and added to the total an actual decrease in plant production results. It has been shown by several records of plant production that the yield decreases on a cold day and increases to a point well above the average on the first warm day after a period of cold weather. A plant in a hot climate on keeping records of the variations in production and attempting to determine the factors concerned, found that in general the production usually varied from day to day with the temperature, but at times varied in the opposite direction. The operators believed that the cause was to be found in a combination of atmospheric conditions, including temperature, barometric pressure, and humidity, which undoubtedly would affect evaporation and cooling of water used either in towers or sprays. To what extent these conditions control the production or account for the variations in it, it is not possible to say.

Another plant that had been treating the same quantity of gas daily from the same wells for nearly three years suddenly increased its production from 5,200 to 5,900 gallons per day, averaged over a period of one month, no changes having been made in plant practice. The operators believed that the increase was due to some change in underground conditions that permitted the gas to be enriched. Exceedingly careful records have been kept at this plant, and these show that the daily production usually varied between 100 and 300 gallons. The sudden increase of 700 gallons daily over a period of one month has not been satisfactorily accounted for. The gravity of the condensate remained constant.

Usually the gravity of the total plant product increases in cold weather, owing to the separation of part of the heavy fractions in the gathering lines and to the condensation of lighter fractions in the water-cooled coils.

It appears that a satisfactory explanation of the causes of variation in production will not be arrived at until complete records of the variations in yield and gravity of the condensate, in the tem-

peratures and pressures used, and in atmospheric conditions are kept at different plants so these data can be studied with reference to each other and a comparison made of the results obtained at a number of plants in different fields and under different climatic conditions.

THE USE OF AMMONIA AS AN AUXILIARY COOLING AGENT.

DESCRIPTION OF PLANT IN FULLERTON FIELD.

A detailed description of plant 2, which is situated in the Fullerton, California, field follows: The casing-head gas being treated in the plant is brought from 20 oil wells through 3,500 feet of 2, 4, and 6 inch lines, 2-inch lead lines from the different wells being connected with the main gathering lines of 4 and 6 inches diameter.

The 6-inch main discharges the gas at the plant into a 6-foot by 10-foot steel receiver which also acts as a scrubber and accumulating tank for "line distillate," removing from the gas the crude oil, the condensate formed in the pipe lines, and dirt. The receiver is connected to a single-stage, 40-horsepower, noncondensing, direct-connected air compressor with 12 by 16 by 12 inch cylinders. The compressor is steam driven, rate 200 revolutions per minute, and takes steam at a pressure of 110 pounds. The compressor holds on the intake receiver a 10-inch vacuum that brings the gas through the pipe lines from the well, but is practically dissipated by friction and leakage, leaving the pressure at the wells at or near zero.

REFRIGERATION "STILLS."

Seven "stills," or coil heat interchangers are used in cooling the gas. (See fig. 11.) Each still consists of 1,260 feet of 1¼-inch, extra heavy pipe coiled, with return bends, inside of a 12-inch tube 80 feet long laid at a slope of 1 inch in 10 feet, or 8 inches in all, to collect the condensate at one point, thence it is drained into storage or "make" tanks. The seven stills are parallel with one another, all draining in the same direction. Four of the stills, in which ammonia is used as the refrigerant, are insulated by about 1 foot of sawdust contained in a wooden housing about the tube; the other three coils, which treat the hot gas from the compressor, are not insulated and are exposed to the air, the hot gas flowing in the 12-inch tube and the cold gas in the 1¼-inch coils.

The compressor discharges the gas at a pressure of 37 pounds and a temperature of 150° F. into stills 1 and 2, connected in parallel. These stills discharge into the outer tube of still 3, the gas from this still flowing through the outer tube of each of the other stills in succession. The dry, cold gas from still 7, in which the lowest temperature, approximately 10° F., and the final precipitation of condensate are obtained, is discharged into a pipe which returns it to the 1¼-inch

coils of stills 1, 2, and 3. The gas is divided equally between the three coils of these stills, flowing through them in parallel, thence it discharges into a header connected with the field, or "dry-gas," lines carrying it back to the various leases.

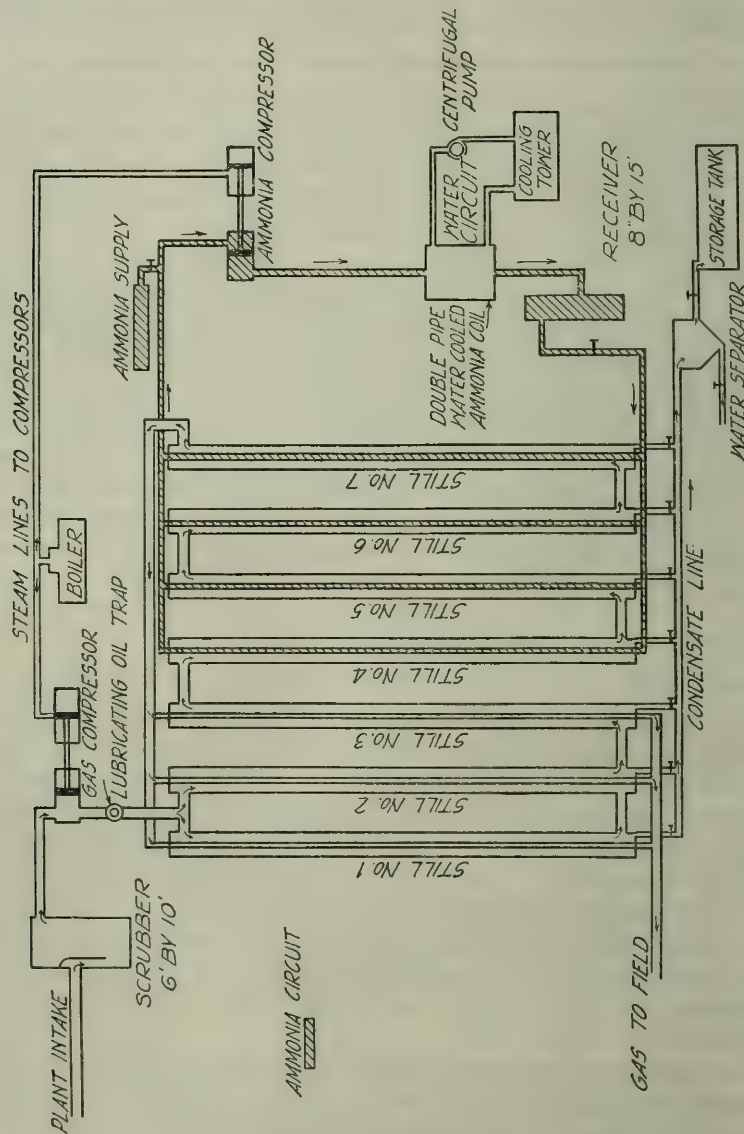


FIGURE 11.—Flow sheet of compression plant in Fullerton, California, field.

TEMPERATURES OBTAINED.

The following table gives the average temperature of the gas as it enters each of the stills; also the average gravity of the condensate discharged at the low end of each still. The gravity of the mixture of the entire product from all the stills averages 76° B.

Temperature of gas and gravity of condensate from each of the seven stills.

	Temperature of gas in each still, °F.	Gravity of condensate, °B.
Stills 1 and 2	150	62
Still 3	75	65
Still 4	50	73
Still 5	40	78
Still 6	30	85
Still 7	10	95

COOLING SURFACE.

In each still the 1,260 feet of 1¼-inch pipe exposes a radiating surface of 412 square feet to the wet gas being refrigerated in the 12-inch tube, or 2,884 square feet in the entire set of seven stills. Of the 2,884 square feet of surface area, 1,648 feet are cooled by ammonia in stills 4, 5, 6, and 7, and 1,236 feet by cold, dry gas in stills 1, 2, and 3 that has passed through the entire set of refrigerating tubes, giving a total of 8.24 square feet of cooling surface for each 1,000 cubic feet of gas treated per day.

COLLECTING CONDENSATE.

The condensate from each still is drawn off continually from the bottom at the low end through a 1-inch pipe manifold to a cone-bottom settling tank in which the gasoline and the water separate by gravity, the water being drawn off at the bottom and the condensate flowing to the storage tanks. The 1-inch manifold and the bottom of each still are connected by a ½-inch gage glass through which the condensate precipitated in that still flows, allowing the operator to see at all times the flow of condensate before it is mixed with that of other stills. By this arrangement he can note, without stopping the plant, whether any discolored condensate is being discharged, or whether any one of the stills is not working properly.

AMMONIA CIRCUIT.

The ammonia used in refrigeration is compressed in the duplex compression cylinders of a 30-ton Stevens ice machine, direct-connected to a 125-horsepower, tandem-compound, steam-driven Corliss engine, with 10 by 20 by 12 inch cylinders taking steam at 110 pounds and operating at 80 revolutions per minute.

From the compression cylinders the ammonia gas is discharged at a pressure of 150 pounds to the inside 1¼-inch pipe of a double-pipe water-cooled coil, the water circulating through the outside 2-inch pipe. This coil unit consists of three sets of double-pipe return-bend coils eight pipes high and 20 feet long. Water circulated by a centrifugal pump flows from the coils over a cooling tower, collects in the tower basin and is returned to the coils by the pump at a temperature somewhat below that of the atmosphere. From the inside coils the ammonia flows through a ½-inch pipe to a receiver or storage tank,

made of 8-inch casing 15 feet long, thence through an expansion valve to the four stills, connected in parallel as described above, at a pressure of 15 pounds and a temperature of 10° F. The ammonia is discharged from the four stills into a pipe manifold leading to the ammonia compressor, to be returned through the circuit. Ammonia lost in the pipes and stills by leaks and breaks is replaced from time to time from a steel bottle of compressed ammonia connected to the ammonia circuit as indicated in figure 11.

DESCRIPTION OF PLANT IN SANTA MARIA FIELD.

Plant 10 uses ammonia as an auxiliary cooling agent in addition to water cooling and expansion cooling. At this plant the gas passes through water-cooled coils after each of the three stages of compression, then through a coil cooled with brine refrigerated by ammonia from an ice-making machine, and then through double-pipe coils cooled by expanding gas.

The gas, after being cooled in the high-pressure (250 pounds) water-cooled coils, is led through a continuous coil of 4-inch pipe 450 feet in length, inclosed in a wooden tank or basin built with double walls and bottoms, 9 inches apart, the space between the walls being packed with sawdust. This coil is cooled with brine. The tank bottom has enough slope to drain the brine toward one end, whence it is pumped for recirculation through the unit. The brine (calcium-chloride solution) is brought in contact with the expanded ammonia by the use of coils in an iron tank, reducing the temperature of the brine to about 32° F. From this cooling tank the brine is circulated by a centrifugal pump to the gas-cooling coils, where it is discharged in such a way as to drip over the coil and collect at the low end of the basin, to be discharged again to the ammonia-cooled brine tank.

The gas discharged from the brine-cooled coils has a temperature of 32° to 34° F. The advantage claimed for this system is that the temperature produced by the brine cooling precipitates all the water vapor in the gas, thus preventing freezing of the double-pipe coils cooled by gas from the expansion engine. This is without doubt an advantage to be desired, but it could probably be obtained in this plant, as in other plants, by a more thorough use of expanded gas in coils of greater length and smaller diameter, or by using the expanded gas in two sets of coils and cooling the high-pressure gas in two stages, the first stage using the expanded gas from the second-stage coils. The first coils being partly warmed, would precipitate only water if the temperature were properly adjusted as is done in other plants described. The ammonia compressor and coils, also the brine circulating pumps, coils, and cooler could be abandoned, and only the extra set of expansion coils put in to replace them.

The brine and ammonia cooling installation is cumbersome, inefficient, and requires more time and care than the result warrants.

TREATMENT OF STILL VAPORS BY COMPRESSION AT A REFINERY IN NEW JERSEY.

VAPORS TREATED.

The gases treated in the compression plant, designated as plant 80 in the tables, at a refinery in New Jersey are those from all cooling coils in which the lighter fractions of crude oil and naphthas from both fire and steam stills are being condensed. Figure 12 shows (at the extreme left) the condenser box and coils from which the uncondensed gases and vapors treated by compression originate. From that point each unit and process is shown diagrammatically to the point at which the condensate and fixed gases are finally separated

COLLECTING VAPORS.

At the discharge pipe of the coils in water boxes a T connection is made, the condensate flowing down into pipes connected with the "tail house" and "look boxes"; the gases and vapors rise through a vertical pipe 6 feet high to the 8 or 10 inch collecting pipe called the gas main. The gas main is also connected with a 2-inch pipe to the condensate line at a point about 2 feet back of the look boxes, and with a 2-inch pipe leading from the top of the look boxes, both of which are used to relieve the pressure and collect vapors that have been carried past the first stage of separation, or have formed in the condensate flow lines. From the top of the gas main the gas is led through 12-inch pipe connections past a butterfly valve, which regulates the vacuum held on the discharge pipes of the condenser coils, to a vertical steel receiving tank 15 feet in diameter and 18 feet high. In this tank the gas is given a preliminary scrubbing with sea water, removing part of the sulphur compounds, some heavy oils which have been carried through the stills, and a small quantity of discolored condensate of approximately 53° B. gravity. The 12-inch pipes leading to the receiver are taken out at the top of the gas main, instead of the bottom, so as to trap back any condensate formed in the main and allow it to flow down the 6-foot risers and back into the lines from the coils to the tail house with the rest of the condensates produced. The vacuum held and regulated by the butterfly valve, previously referred to, on the gas mains and on the discharge of the condenser coils is between 0.25 and 1 inch of mercury (2 to 8 ounces below atmospheric pressure). There is no gage between the butterfly valve and the blower that produces the vacuum, so no record of the pressure between these points is available. However, the writer was informed that a test had been made that showed a vacuum of 22 inches of mercury.

SCRUBBING PROCESS.

From the receiving tank a 12-inch pipe carries the gas to a size 8 positive-pressure Root blower which holds the vacuum on the re-

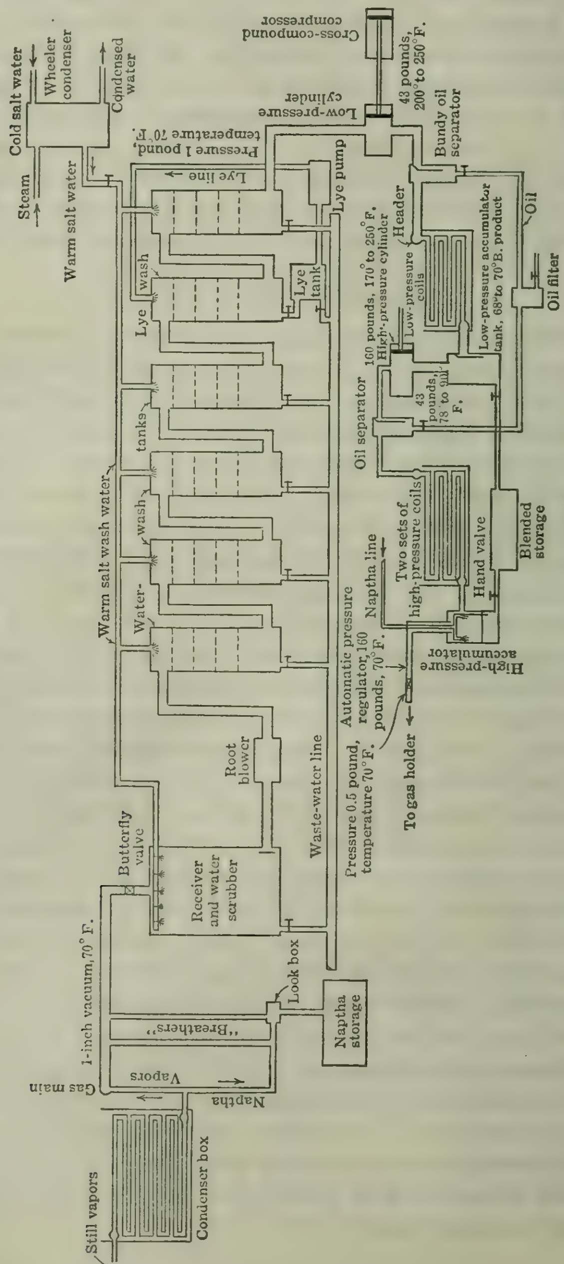


FIGURE 12.—Flow sheet of compression plant at a refinery in New Jersey.

ceiving tank and the gas mains and delivers the gas at a pressure of one pound to the scrubbers and the low-pressure compressor beyond

the scrubbers. From the blower the gas passes through six 4 by 20 foot vertical iron scrubbers connected in series. The connections are so made that by opening or closing valves, the scrubbers may be operated as two sets, in parallel, of three tanks connected in series. This arrangement was tried and abandoned in favor of the series of six. In each scrubber the gas enters at a point about two feet above the bottom, passes a series of wood baffles over which warm wash water or caustic solution is falling, and discharges at the top. The gas then passes through the next scrubber in the series.

In the first four scrubbers warm sea water, flowing over baffles countercurrent to the gas, is used to remove impurities, consisting chiefly of sulphur and sulphur compounds, from the gas. In the fifth scrubber a solution of sodium hydroxide (lye) with a specific gravity of 12° B. is circulated over the wood baffles, in the same manner as the water in the other tanks, to remove any acids contained in the gas. These impurities may originate either in the crude oil or in the refining of the various distillates from which vapors are taken for treatment by compression. The lye used, as received at the refinery from the manufacturer, is a 35° to 40° solution. It is transferred to one of four iron storage tanks and diluted to the strength used in the scrubber. After being circulated until it will not neutralize the acid in the gases and becomes foul, it is wasted and fresh solution is put into circulation.

In the sixth scrubber warm salt water is used to remove any traces of caustic remaining in the gas. Caustic in the gas would react with the lubricating oils in the compressor cylinders, causing cutting of the cylinders or an excessive waste of oil.

The gas in passing through the six scrubbers is warmed 2° to 5° F. by the warm water used as the scrubbing medium. This warm salt water is the discharge from the Wheeler condenser used in connection with the low-pressure steam cylinder of the compressor. The fact that the water used is salt has nothing to do with the process. Sea water is used because it is the most available, the plant being situated on the Atlantic coast. No condensate is formed during the scrubbing. This would be anticipated because of the increased temperature of the gas due to the use of the warm condenser water. Both the water and the lye solution circulated through the scrubber tanks are handled by duplex pumps.

COMPRESSION AND COOLING.

From the sixth scrubber the gas is delivered at a pressure of 1 pound and a temperature of 70° F. to the low-pressure cylinder of the compressor, which discharges it at a pressure of 43 pounds and a temperature varying between 200° and 250° F.

Gas discharged from the low-pressure cylinder to the intermediate cooling coils is passed through a Bundy oil separator, which removes

lubricating oils carried over with hot gas and gasoline vapor from the compressor cylinder. The coils used are the water-cooled type submerged in a box, typical of refinery construction. The gas is divided in a header into six sets of return-bend coils of 3-inch pipe 10 feet long and six pipes high, totaling 360 feet of 3-inch pipe, exposing a radiating surface of 283 square feet, or 0.189 square foot per 1,000 cubic feet of gas treated per day. This is approximately one-third of the radiating area usually found in compression plants for the same service.

At the bottom of the coil the gas is again collected through a header and discharged into an accumulator tank in which 750 to 1,000 gallons of condensate is collected each day. The condensate varies in gravity according to weather conditions, averaging 68° B. in summer and 72° B. in winter. The product collected in this accumulator tank is forced into storage tanks by the working gas pressure as often as necessary and blended with the rest of the condensate. The gas leaving the coils has a temperature of 70° to 90° F., the high temperature probably being due to the small cooling area used at this plant.

At this temperature and pressure (70° to 90° F. and 43 pounds) the gas enters the high-pressure cylinder and is discharged at a pressure of 160 pounds and a temperature between 170° and 250° F. The gas is again led through a Bundy trap to separate lubricating oils, as previously described, and then to the high-pressure cooling coils, which are the same size and length as the intermediate coils used to cool the low-pressure gas, except that two sets are used in series in place of one, having twice the cooling area. The average temperature to which the gas is reduced in these coils is 70° F. and is the lowest temperature used in the treatment.

After the condensate and gas have been separated in the high-pressure accumulator tank the pressure is reduced through a valve to one-half pound and the gas discharged to a gas receiver in which gas is stored and used for fuel under boilers, stills, etc., in the plant.

BLENDING.

Blending at this plant is all done under a pressure of 160 pounds in the high-pressure accumulator tank, as follows:

Naphtha with a gravity of 53° B. is pumped through $1\frac{1}{4}$-inch pipe in coil boxes and cooled to 70° F., then into the top of the high-pressure accumulator tank, and sprayed through the rising gas at a rate which gives a mixture containing approximately four parts of naphtha to one of condensate, or about 80 per cent naphtha. At regular intervals the mixture is drawn off into another tank containing the low-stage condensate, and the resulting mixture sampled and tested for gravity. If the gravity is found to be too high, more

naphtha is pumped into the accumulator tank, which lowers the gravity of the next batch drawn off into the storage tank and of all the blend in storage, or if the gravity was too low the proportion of naphtha pumped into the accumulator is cut down. From 4,000 to 5,000 gallons of raw condensate is made daily in the high-pressure coils, and this with the condensate from the low-pressure coils makes a total production of 5,000 to 6,000 gallons per day from treated gases and vapors. The raw condensate from the high-pressure coils has a gravity varying between 76° and 93° B. After blending with naphtha, the product has a gravity of 58° to 61° B.

The level of the mixture in the high-pressure accumulator tank is at all times kept above the discharge pipe from the coils, thus forcing all the gas to pass through the blended product. It is claimed that this method adds 250 to 500 gallons daily to the net production. Inasmuch as the blend is four parts naphtha to one of condensate, and the temperature of the gas in the coils is such as to leave part of the comparatively heavy gasoline fractions uncondensed, absorption of liquids from the gases or absorption of the gases themselves may reasonably take place. The general practice throughout the United States, however, is to remove the condensate from contact with the gas as soon as possible.

QUANTITY OF GAS TREATED, AND PRODUCTION.

The volume of gas treated is computed from the compressor displacement, and the record of engine revolutions with 5 per cent deducted for slippage. On this basis the gas passing through the plant varies between $1\frac{1}{2}$ and 2 million cubic feet per day, and shows an average production of 3.09 gallons of condensate per 1,000 cubic feet of gas treated.

COMPRESSOR.

All gas compressed passes through a 2-stage Corliss-valve compressor, direct connected to a combination cross-compound, condensing Corliss engine; steam cylinders are 16 and 32 inches in diameter with 30-inch stroke. The compressor speed varies greatly, being dependent upon the amount of gas coming from the stills, which in turn depends upon the stage of distillation of oil at which the various stills are working.

SPECIAL FEATURES OF PLANT.

The noteworthy features of this compression plant are the scrubbers for removing sulphur and acid, the Root blower as a booster unit, the passing of gas through the condensate to bring about greater production of gasoline condensate by absorption, and the large amount of naphtha used in the blended product.

MACHINES USED IN COMPRESSION PLANTS.

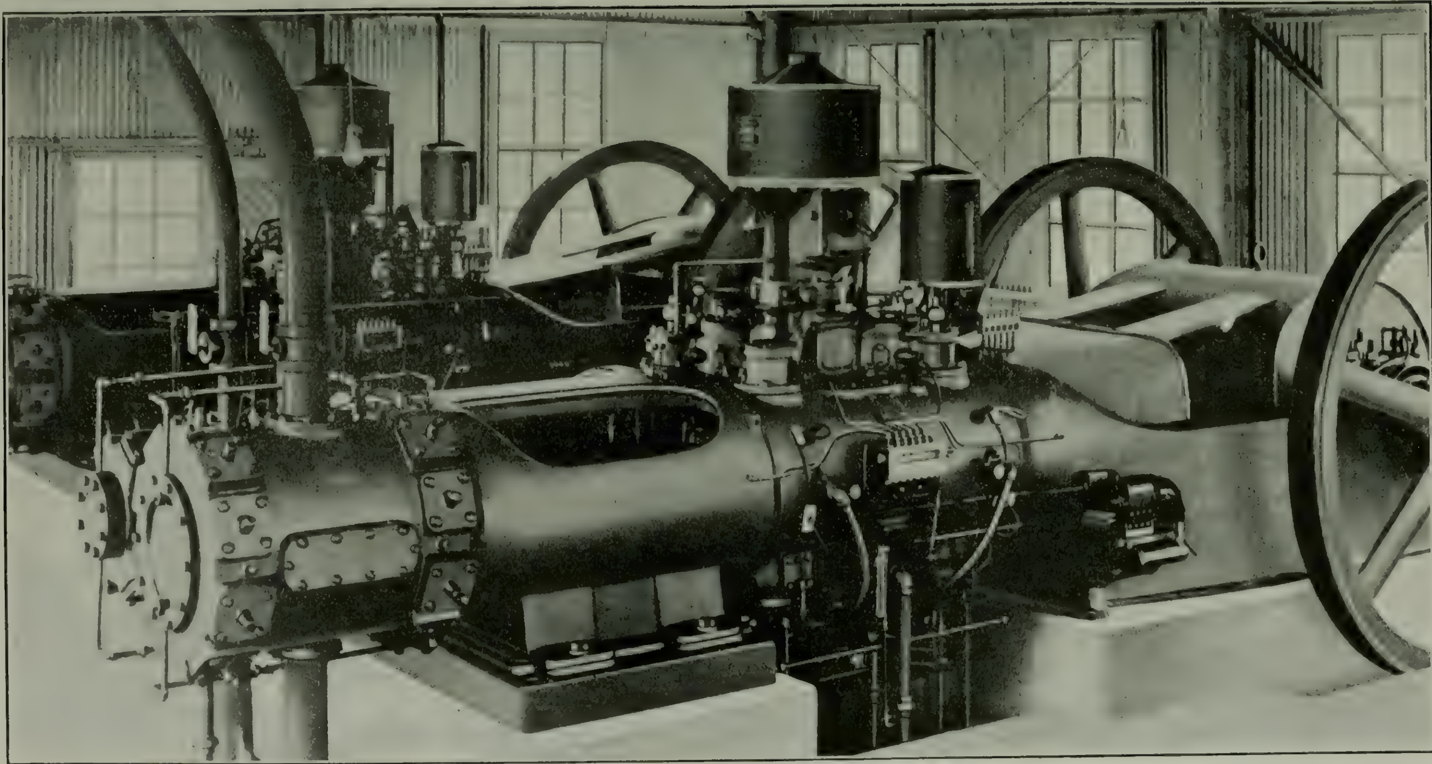
Table 7 shows the total rated horsepower used in gas compression in each of the plants listed, and the number of cubic feet of gas compressed per day by one rated horsepower.

TABLE 7.—*Rated horsepower and capacity of various plants.*

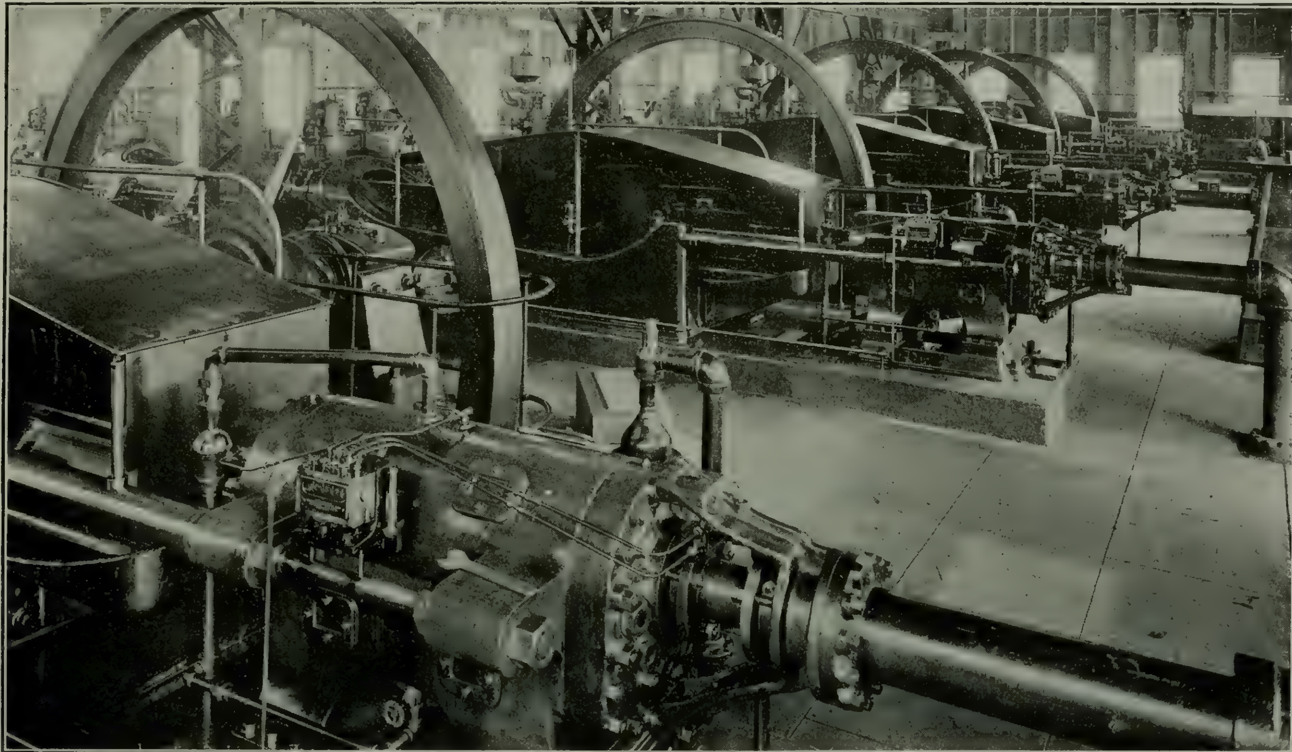
Plant No.	Total rated horse-power.	Cubic feet of gas compressed daily per horsepower.	Plant No.	Total rated horse-power.	Cubic feet of gas compressed daily per horsepower.
3	110	4,100	34	300	2,500
4	300	4,000	35	100	3,500
7	1,800	4,160	36	480	2,400
9	320	3,200	37	170	2,300
11	480	3,100	38	300	2,500
12	240	2,917	50	320	3,700
14	330	3,030	51	110	2,170
16	100	2,500	52	100	2,500
17	300	2,500	54	900	2,500
19	575	3,080	55	300	4,170
20	495	3,030	56	210	1,800
21	300	3,300	57	350	2,400
22	180	3,300	76	300	6,750
30	210	3,500	77	50	8,000
32	695	4,300	78	50	900
33	560	3,200	79	105	2,380

The quantity of gas compressed or treated per horsepower in the plants visited varies between wide limits. The chief causes for this variation are that the intake pressures vary widely and also the final pressures vary between 75 and 300 pounds. Many other factors in plant operation also affect the results, among which are the actual efficiency of the engine and compressor used, the temperature of the gas at different stages, the sizes and length of pipes through which the gas is forced, and the power used in driving pumps and line shafts, which in many plants is taken from the engine that drives the compressor. In plants where expansion engines are used to compress gas no attempt has been made to estimate or add the power delivered by such units.

The table shows that the average plant visited by the writer has 340 horsepower and treats approximately 3,250 cubic feet of gas per day for each rated horsepower installed. The conditions under which many of these plants are operating may be found in Tables 3, 4, and 5. Among operators who design plants and use the rated horsepower, rated compressor capacity, and atmospheric pressure at the intake, with a discharge pressure of 250 pounds, 4,000 cubic feet of gas daily per horsepower is used for preliminary estimates of the requirements of a plant to treat a given volume of gas. The final estimates necessarily must include all the items mentioned above, and also take into consideration all of the special conditions under which the plant in question is to operate.



TWO-STAGE DIRECT-CONNECTED COMPRESSOR AND GAS ENGINE.



FIVE 485 BRAKE-HORSEPOWER GAS ENGINES, FRONT-CONNECTED TO 15½-INCH COMPRESSOR CYLINDERS, AT A WEST VIRGINIA PLANT THAT COMPRESSES NATURAL GAS TO A PRESSURE OF 275 POUNDS GAGE DISCHARGE. IS FIELD END OF A 20-INCH PIPE LINE.

ENGINES AND POWER.

Machines of practically all well-known manufacturers making gas engines or compressors have found their way into compression plants. One company which has done much pioneer work in both the laboratory and the field, tending to develop the natural-gas gasoline industry, has placed its engines, compressors, or both, in many plants in every field visited by the writer.

Plates XIII and XIV show engine installations at two compression plants.

Table 8 gives data on the motive power, types, and sizes of engines and compressors, method of connection, and the number of compressor units used in the plants visited.

In plant 24, electric motors have been installed to drive the compressors. Originally gas engines were used, but the gas being treated became so rich in gasoline content that not enough gas was discharged after treatment to operate the engines. The motors are set on the blocks that were used for engine beds and are in the same room with the compressors. Because of the possibility that gas may escape about the compressors and be ignited by sparks from the motors, this arrangement would appear to be dangerous practice, but thus far, owing probably to especial precautions in ventilation, no fires or explosions have occurred.

Plants 19, 20, and 21, all built in 1916, use vertical 4-cylinder, 4-cycle gas engines belted to the compressor units. While this type of machine has many moving parts which may get out of order, and a long crank shaft with its bearing to watch and tighten, it is giving complete satisfaction and is claimed to economize fuel and give an overload capacity of 25 per cent.

The 450-horsepower, direct-connected, 4-cycle, double-acting machines, although recognized as standard installations in gas-pumping plants throughout the country, have a number of disadvantages as units for the treatment of gas for gasoline extraction. A machine of this size should be installed only in plants that draw gas from areas large enough to insure a supply for a long term of years, and are of such capacity that one of these large units represents only a small fraction (10 to 20 per cent) of the total plant capacity, otherwise shutting down one unit unbalances the entire plant and materially reduces the output.

TABLE 8.—*Data on engines and compressors*

Plant No.	Engine. Driven by—	Rated horse-power.	Type.[a]	Number of compressors used.[b]	Drive.
1	Steam		Cross compound	2	Direct
2	do	40	Straight line	2	do
3	Gas	110	Straight-line, tandem, 2-cycle	1	Belted
4	do	150	Twin cylinder	2	do
6	Steam		Cross compound condensing	1	Direct
	do		Tandem compound condensing.	1	do
	do		do	1	do
	High-pressure gas.[c]		Cross compound, 12 by 25 by 30.	1	do
7	Gas	450	Tandem, 4-cycle, double-acting.	2 low	do
	do	450	do	2 high	do
	High-pressure gas.[c]		Cross compound	1	do
8	Gas				do
9	do	80	Type VII, 16 by 20	2 high and 2 low	do
	High-pressure gas.[c]		Cross compound, 12 by 18 by 10.	1	do
10	Steam		Cross compound, 12 by 20 by 12.	2	do
	do		Simple, 12 by 12	1	do
	High-pressure gas.[c]		do	1	do
11	Gas	80	Type VII, 16 by 20	6, 3 high and 3 low	do
	High-pressure gas.[c]	50	Simple, 12 by 12	1	do
12	Gas	80	Type VII, 16 by 20	4, 2 high and 2 low	do
	High-pressure gas.[c]		Drilling engine, 9 by 12	1	Belted to pump.
14	Gas	110	Twin	3	Belted
	High-pressure gas.[c]		Simple, 10 by 12	1	Direct
16	Gas	50	Type VII, 13½ by 18	2, 1 high and 1 low	do
	High-pressure gas.[c]		Simple, 10 by 12		do
17	Gas	150	Twin cylinder	2	Belted
	High-pressure gas.[c]		Simple, 12 by 11	1	Direct
19	Gas	175	Vertical, 4-cylinder, 4-cycle	3	Belted
	High-pressure gas.[c]		Duplex pump, 10 by 12 by 6.	2	
20	Gas	165	Vertical, 4-cylinder, 4-cycle	4	do
21	do	150	do	4	do
22	do do	Two 40 Two 50	Type VII	4, 2 high and 2 low	Direct
23	do	35	Single cylinder	1	Belted
24	Electricity	35	Motor	2	do
25	Gas	50	Type VII	2	Direct
27	do	85–100	Horizontal	2	Belted
28	do	100	do	1	do
29	do	50	Single cylinder	1	do
30	do	70	do	3	do
31	do	110	Twin	2	do
32	do	165	do	9, 4 running	do
	High-pressure gas.[c]		Cross compound, 12 by 19 by 18.	1	Direct
33	Gas	Eight 50 Two 80	Type VII	10, 5 high and 5 low	do
	High-pressure gas.[c]		Cross compound, 8½ by 12 by 12.	1	do
34	Gas	50	Type VII, 13½ by 18	6, 3 high and 3 low	do
37	do	70	Single cylinder	1	Belted
	do	50	Type VII, 13½ by 18	2, 1 high and 1 low	Direct
38	do	50	Single-cylinder, 13½ by 18	6, 3 high and 3 low	do
50	do	80	Type VIII, 16 by 20	do	do
51	do	110	Twin-cylinder	1	Belted
52	do	50	Type VII, 13½ by 18	2, 1 high and 1 low	Direct

[a] Figures show size of cylinder in inches.
[b] In this column "low" refers to low pressure, "high" to high pressure.

used at various compression plants.

Compressor.				
Description.	Size of cylinder (inches). Low-pressure cylinder.	Size of cylinder (inches). High-pressure cylinder.	Rated speed (r. p. m.).	Remarks.
2-stage	21 by 24	9½ by 24	62	
Single-stage	12 by 16		200	
2-stage	13½ by 14	6½ by 14	160	
do	16 by 16	8 by 16	180	
2-stage	20 by 24	9½ by 24	125	Two 300-hp. Sterling and four 150-hp. Erie boilers used.
do	15 by 24	7 by 24	145	
do	15 by 16	7½ by 16	115	
do	24 by 30	12 by 30	38	
Single-stage	31 by 36		125	
do		15½ by 36	125	
Single-stage (duplex).	Two 22 by 16			
Single-stage	14 by 20	7½ by 20	200	
2-stage	16 by 10	8 by 10	100	
do	20 by 12	12 by 12		Used as low and intermediate at 12 pounds and 80 pounds.
Single-stage		8 by 12	Varied.	Used as high at 250 pounds.
do	14 by 12			Used as air compressor.
do	Three 14 by 20	7¼ by 20	180	
do	14 by 12		145	Pumps dry gas at 60 pounds.
do	Two 7 by 20	Two 14 by 20	190	
2-stage	13 by 14	6½ by 14	170	
2-stage, tandem	8 by 12	4 by 12	200	
Single-stage	11 by 18	5½ by 18	180	
do	12 by 12			
2-stage	16 by 16	8 by 16	150	
Single-stage	20 by 11		78	
2-stage	16 by 16	8 by 16	158	Engine speed, 300 revolutions per minute.
				Water discharge throttled to 100 pounds.
do	16 by 16	8 by 16		Drilling engine, 10 by 12-inch cylinder, used as expansion engine.
do	16 by 16	8 by 16	150	Engine speed, 275 revolutions per minute.
Single-stage				Drilling engine, 10½ by 12-inch cylinders, used as expansion engine.
2-stage	11 by 15	7 by 15	115	
do	14 by 10	7¾ by 10	120	
Single-stage (to 150 pounds).			180	
2-stage	12½ by 14	6 by 14	180	
do	12½ by 14	6 by 14	180	
do	10½ by 12	5¼ by 12	180	
do			180	
do	14 by 14	7 by 14	180	
do	16 by 16	8 by 16	180	
Single-stage (duplex).	18 by 18			Feather valves on compressor.
Single stage	Eight 12 by 18. Two 14 by 20.	Eight 6½ by 18. Two 7 by 20	200	
Single-stage (duplex).	14 by 12			
do	12 by 18	9 by 18	100	
2-stage	12 by 12	6 by 12	180	
Single-stage	10 by 18	5½ by 18	180	
do	12 by 18	6 by 18	180	
do	14 by 20	7 by 20	180	
2-stage	13 by 14	6 by 14	160	
Single-stage	12 by 18	6 by 18	180	

[c] Expansion engine operated by expanding high-pressure, treated gas through it.

TABLE 8.—*Data on engines and compressors*

Plant No.	Engine.				
	Driven by—	Rated horse-power.	Type.	Number of compressors used.	Drive.
53	Gas	[a] 80 [b] 50	Type VII	2, 1 high and 1 low	Direct
	do	80	Type VIII	do	do
	do	150	Twin	1	Belted
	do		2-cylinder, tandem	1	do
54	do	50	Type VII	6, 3 high and 3 low	Direct
	do	150	Twin-cylinder	2	Belted
	do	150	do	2	do
55	do	50	Type VIII	6, 3 high and 3 low	Direct
56	do	70	Single-cylinder	3	Belted
57	do	70	do	5	do
58	do	50	Type VIII		Direct
59	do	50	do		do
60	do	50	do		do Belted
61	do				do
62	do	50	Type VIII		Direct
76	do	50	Type VIII, 13½ by 18	4	do
	High-pressure gas.[c]		Duplex, 13½ by 18	1	do
77	Gas	50	Type VIII		do
	High-pressure gas.[c]				
78	Gas	50	do	1	Direct
			Pump, 10 by 6 by 12	2	
79	do	35	Single cylinder	2	Belted
80	Steam		Cross compound, Corliss, 16 by 32 by 30	1	Direct

[a] Low pressure. [b] High pressure.

used at various compression plants—Continued.

Compressor.				
Description.	Size of cylinder (inches).		Rated speed (r. p. m.).	Remarks.
	Low-pressure cylinder.	High-pressure cylinder.		
Single-stage				
do				
2-stage	15½ by 16	7½ by 16		
do	14 by 14	6½ by 14		
Single-stage	11 by 18	6 by 18	180	
2-stage	16 by 16	7 by 16	180	
do	16 by 16	7 by 16	180	
Single-stage	11 by 18	5½ by 18	180	
2-stage	12 by 12	6 by 12	180	
do	12 by 12	6 by 12	180	
Single-stage	11½ by 18			
2-stage				Compresses air in two stages to 85 pounds.
Single-stage	11½ by 18			
do				
	11½ by 18			
2-stage	12 by 12	6 by 12		Feather valves on compressor.
do	25 by 30	13 by 30		Corliss valves on compressor.

[c] Expansion engine operated by expanding high-pressure, treated gas through it.

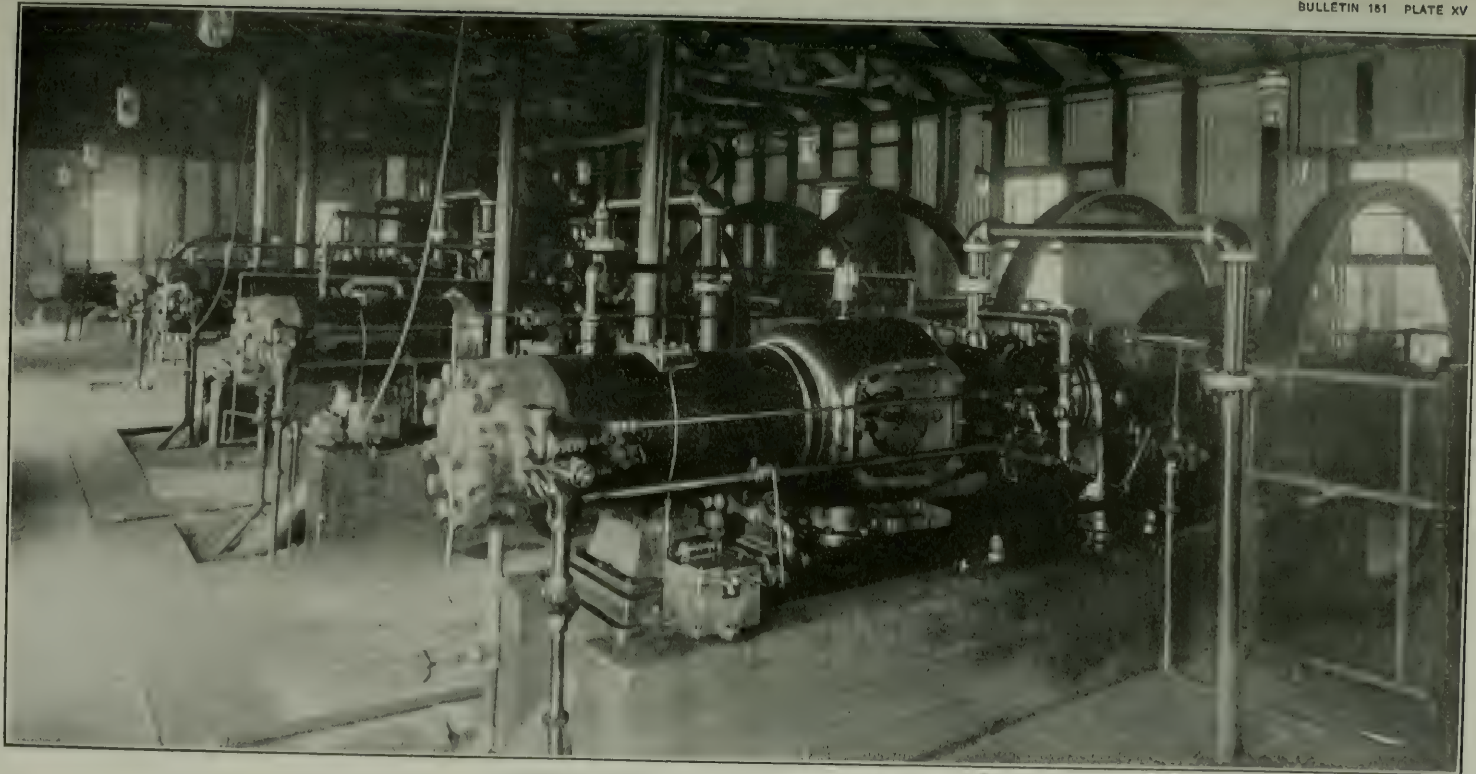
In the casing-head gasoline industry the gas supply from a given area is expected to decline and the pressure necessary to precipitate the condensable product usually becomes lower as the gas becomes richer. If all the power capacity thus relieved from duty is not used to increase the vacuums held on the lines, it is obvious that to remove one unit to another locality would be desirable. If one unit represented half the total plant capacity, it would be necessary to wait until the available supply of gas had been reduced 50 per cent before that unit could be transferred, but if that unit represented only 20 per cent of the plant capacity it could be removed when the gas had fallen off that amount; also it would be a much simpler matter to find a location or sale for a machine of one-half million feet capacity than for a machine requiring from three to four million feet per day. Another argument for machines of smaller capacity is the size and weight of parts which under the usual transportation conditions in oil fields is a serious problem in plant construction.

Both direct-connected (Pl. XV) and belted units are being installed in compression plants using the usual smaller units. However, many operators of wide experience prefer the belted drive, claiming that it simplifies repairs and renewals and gives a wider choice both of engine and compressor. The belted type requires larger buildings, because of the necessary distance between pulley centers, which the writer found to vary between 22 feet for vertical engines to 34 feet for horizontal types. In some plants two buildings are used, one containing the engines and the other the compressors, with belt galleries connecting the two. This is done as a precaution against fire and explosions.

TYPES OF MACHINES USED AS EXPANSION UNITS.

All expansion engines used in compression plants are machines originally designed to use steam that have been slightly modified to overcome the effects of the low temperatures from the use of compressed gas in the steam or power cylinders. Among the machines found in use are direct driven reciprocating pumps, drilling engines, and simple and cross compound compressors. Of these the reciprocating pump is the least to be recommended. The valves tend to freeze and stick, owing to the general design and slow action, and its efficiency as a power unit and its capacity are low.

Of the machines used as expansion engines the converted steam engine of the single or double stage (simple or compound) type is more often found than any other make. On these engines, remodeled for the expansion of high-pressure gas, the valve mechanism has been designed especially and made stronger for this particular service. The exceedingly low temperatures developed in the cylinders tend to freeze the valves, causing excessive strains on the valve stems and rods, and also make lubrication difficult.



DIRECT-CONNECTED COMPRESSOR AND GAS ENGINES.

Glycerin has universally been found to be the best lubricant for expansion cylinders and was in general use until the recent rise in price, and the difficulty of obtaining a reliable supply forced plant operators to try other oils, some of which have been found usable but not as satisfactory as glycerin. As the supply of that lubricant increases it will indoubtedly again be generally used.

Other types of steam compressors and, in several plants, drilling engines belted to plunger or centrifugal pumps, are in use as expansion units, and, according to the operators using them, are giving satisfaction in regard to both capacity and temperatures. The loads of the drilling engines were varied to meet the conditions of pressure and volume of gas by throttling the flow of water from the pump, thus giving the required resistance for the development of power at normal engine speeds. The valve mechanism of the drilling engines was rebuilt and strengthened to meet these conditions.

At one plant where a drilling engine gave much trouble from freezing the piston rings were removed and the piston dressed to a square edge. The piston in this condition shaved the ice from the cylinder walls, thus preventing sticking or freezing. No lubricant was used in the cylinder, the film of ice or frost on its walls acting as a lubricant, and leakage past the piston after the film had formed was very small.

At plant 3 an engine of this type that has a 9 by 12 inch cylinder, making 90 revolutions per minute with one-fourth cut-off, takes gas at 130 pounds, gas at 250 pounds being throttled to that pressure, and exhausts it at 10 pounds. The engine is belted to a three-plunger pump throttled to a back pressure of 160 pounds in order to increase the load on the engine. The water pumped is used in the cooling towers and in the engine and the compressor jackets.

At plant 16 the expansion engine, accumulator tanks, and storage tanks are all housed in a double-wall insulated building. The advantage claimed is that the condensate is held at a low temperature in the storage and other tanks, thus preventing loss by evaporation through heating before blending. The condensate precipitated in the coils is kept from sudden and extreme rises in temperature, as would be the case if the storage tanks were not cooled or shaded. The temperature in the building and of the condensate in storage is thus held between 34° and 50° F.

Expanding the compressed, treated gas in engines to develop power for driving compressors or pumps is not an economy, because of the small amount of actual power delivered, the care necessary, and the cost of upkeep and lubrication, such engines being used only because the cooling effect the expanded gas has in the treatment of high-pressure gas in double-pipe coils or heat interchangers.

In simple expansion engines such as pumps, drilling engines, or single-expansion compressors the compressed gas before entering the

power cylinder is often reduced by a throttle valve from the maximum pressure used in the plant to pressures varying between 120 and 160 pounds, depending upon the design and size of the machine and the pressures for which it was built and under which it gives the best results.

Cross-compound machines usually take the gas at the maximum plant pressure and reduce the pressure in the first expansion to 30 to 60 pounds (see Table 5) and in the second stage to between 5 and 15 pounds. Generally the gas goes from the first-stage expansion cylinder to a drip or small accumulator tank, then directly to the low-stage cylinder. In plant 6 (see Table 4, p. 41), the gas from the first-stage expansion is led through a set of double-pipe coils and heated before being put through the second stage of expansion. By this system both the power developed in the expansion engine and the cooling efficiency of the expanded gas are increased, also the danger of freezing in the expansion cylinders is less.

COMPRESSORS.

Direct-connected compressor units are usually of the single-cylinder engine, single-stage type, although some plants in the eastern and Mid-Continent fields are using direct-connected, twin 2-stage machines. Of the direct-connected compressors the single-stage unit, found more often than any other make, as shown in Tables 8 and 9, has the engine and compressor cylinders opposed, or on the opposite sides of the fly wheels.

The sizes and types of compressors used in the various plants visited by the writer are shown in Table 8 (p. 74), which conveys an idea of the great variety of compressors and drives used in such plants.

AUXILIARY MACHINES.

In all natural-gas gasoline plants small engines are needed to circulate water in jackets, towers, and ponds, to produce electricity for light and pump air to start gas engines. The number, situation, and type and size of these units are generally matters of preference with each plant operator and no standard has been followed.

WATER-CIRCULATING PUMPS.

Many of the newest plants have centrifugal pumps belted to a pulley on the engine, which circulate the water used in both engine and compressor cylinder jackets; other plants use a line shaft with pulleys belted to the engines and to the centrifugal pumps. In many fields the water is heavily charged with mineral salts, and the water used in the cylinder jackets is often distilled or condensed and kept separate from that used in cooling the gas coils. This is often done by cooling the condensed water in a separate tower or by passing it through coils

in the main gas-cooling tower that are cooled with spray in the same way that the gas coils are cooled. In the latter method the condensed water is pumped from the coils in the tower through the jackets and back to the coils in a closed circuit. Where a separate tower is used the condensed warm water is sprayed in the tower, collected in the basin beneath the tower, and circulated by pumps through the jackets, and returned to the top of the tower to repeat the cooling and aeration. In this method the loss of condensed water in the tower is so great that it is not to be recommended unless the condensed water is easily made or obtainable from a boiler plant. The cooling effect gained is better, and the installation less expensive, if the cost of condensed water is not an object.

For circulating the water used to cool the gas, usually centrifugal or plunger pumps driven by small (5 to 10 horsepower) gas engines, or belted to a line shaft, are installed.

AIR PUMPS.

Air pumps for compressing air in receivers to start the main gas engines are generally single-cylinder pumps or compressors belted to gas engines, previously mentioned, or, in some plants, to a line shaft driven by a small gas engine. The receivers are built to stand pressures up to 250 pounds. When the desired pressure is built up in the receiver, the air pump is shut down until the pressure is relieved by use in starting the main gas engines, or by leakage, when the pump is again operated until the required pressure is obtained.

LIGHTING EQUIPMENT.

The necessity of using strong, reliable inclosed lights around compression machinery and the danger of open flames in plants treating natural gas at high pressures has forced operators to install small electric generators as part of the equipment of gasoline plants.

The electric plant is always housed in a building separate from the compressors, and usually in the building with the air and water pumps. The unit consists of a gas engine belted to a dynamo of a size and capacity suitable to the lighting needs of the plant, and is operated only at night. In large gas-pumping stations storage batteries are used both for light and for engine ignition, in place of direct connections.

GASOLINE PUMPS.

Plants situated some distance from the shipping point or blending station often require pumps to force the gasoline through the pipe lines to such stations.

The product is often blown from one tank to another by turning high-pressure gas into the tank containing the product, but where the

distance is great this method is not always satisfactory, and pumps of either rotary or reciprocating type are installed, usually being operated by belt connections to small gas engines. It is claimed for the rotary pumps that condensate losses are smaller than from the use of other types, because the agitation is less and the flow more steady and quiet through the pump and into the lines.

BLENDING AND SHIPPING THE CONDENSATE.

Although blending of compression-plant condensates is not done primarily for the purpose of making a product that will meet the specifications required by transportation laws governing the shipment of gasoline by rail or water, blending and shipping have become such important functions, one of the other, that a separate discussion of the blending process and the transportation of the blended stock is not desirable.

REASONS FOR BLENDING.

When the condensate produced by compression is allowed to weather unblended until its vapor tension is reduced to less than 10 pounds at 100° F. and its temperature rises to atmospheric, losses ranging up to 75 per cent of the total product often result, whereas if the condensate is mixed (blended) with heavier straight still-run refinery distillates the losses from weathering are reduced, usually to one-half that amount, and often more. This fact has led condensate producers to take advantage of blending to increase the volume of the product actually marketed, thus increasing their profits and also the supply of marketable motor fuels so desirable under present conditions. The development in gasoline motors up to the present time has not reached a stage that would make the heavier still distillates, such as are used for blending, a convenient or economical fuel if used as made, because of the difficulty in starting the motor with such fuel and its tendency to deposit carbon in the cylinders and on the pistons from incomplete combustion, causing "engine trouble."

Condensate produced by compression is also an undesirable fuel for gasoline engines. It is exceedingly volatile, which causes losses in handling, is dangerous because fumes are easily formed, and gives less power as compared with equal volumes of heavier distillates, a larger number of gallons being required to develop the same power. It gives a quick, sharp explosion in a motor cylinder, but seems to lack "push" after the explosion has taken place. In the above qualities it is in no way different from still-run products of similar gravity and similar end points, both products needing additions of less volatile, heavier, and more powerful fractions in order to form the most convenient and economical motor fuel.

The lighter fractions of petroleum distillates, as compared with the heavier products, have a lower calorific value per gallon but a

higher calorific value per pound. As all products of petroleum are sold in the United States by volume or liquid measure, the standards for comparison must be made on the heat units per volume and not per weight.

As previously stated, another important factor in blending is transportation. The Interstate Commerce Commission rules controlling shipments of petroleum products and liquefied natural gas allow transportation of petroleum distillates having vapor tensions of less than 10 pounds per square inch in standard tank cars, and products with vapor tensions of 15 pounds per square inch in specially built insulated tanks. As many plants produce condensate that has a vapor tension of 30 or more pounds as it comes from the accumulator tanks, blending and weathering are both resorted to by most manufacturers in order to bring the product within shipping rules, to increase the quantity, and to improve the quality of the product.

MARKETING UNBLENDED CONDENSATE.

A small quantity of natural-gas gasoline finds its way to consumers unblended. It is sold as "gas-machine gasoline," a product with a gravity of 80° to 86° B., used to make gas for certain domestic, commercial, and chemical purposes, and as "export gasoline," a product with a gravity of 74° to 80° B. and of 4 to 6 pounds vapor tension, which is usually sold in containers to foreign trade.

The great bulk of condensate, however, is blended in one way or another before it reaches the consumer, but not always completely blended at the plant where it is made, or by the producer.

In many eastern fields the condensate is held in storage under pressure until a given quantity is ready for shipment, when it is forced by gas pressure or pumps through small (2-inch) pipe lines to the tanks of firms making a specialty of blending and marketing motor fuels, and having blending stations centrally situated among the compression plants from which they receive condensate. Products having a gravity as high as 84° B. are shipped in this way to blending companies.

SHIPPING BY AUTO TRUCK.

Another method of shipment, used mostly in California and northern Pennsylvania, is by tanks mounted on auto truck. Two plants shipping condensate of 80° to 83° B. gravity in this way are situated 30 miles from the blending stations of the buying companies. These are unusual examples, but a number of plants ship their product 6 to 10 miles in tanks of this character. Generally the tank is kept under a pressure of 10 to 20 pounds in order to reduce losses of the light condensates from agitation and heating during transportation.

TRANSPORTING CONDENSATE IN CRUDE OIL.

Certain large producing and refining companies in California which buy or produce casing-head gasoline gage the product in the storage tanks at the compression plants for settlement, and have the condensate pumped directly into their crude oil storage or pipe lines leading to their refineries. They not only recover the gasoline when the crude oil is refined, but take advantage of the fact that the condensate "cuts" the crude, making it flow through the lines more easily. The extremely light fractions that are thus injected into the crude oil, and will not condense in the usual refinery condenser boxes, can be and are in many refineries compressed and cooled as in compression plants. This product is immediately blended at the refinery and thus held and sold.

As previously mentioned, a company in the Mid-Continent field produces only such condensates as can be shipped in tank cars. This is done by regulating the pressures and the temperatures used in the compression plant, so that only such condensate as can be shipped unblended will be precipitated.

A plant in California and some plants in other fields reduce the unblended condensate to conform with the shipping rules by weathering, because of the cost of shipping in blending naphtha. The condensate is exposed in storage tanks to atmospheric temperature and pressure until the vapor tension is reduced to the desired point, and then shipped in insulated cars. At times warming with steam is resorted to if the atmospheric conditions do not bring about the proper results. The use of steam is not to be recommended, however, except when absolutely necessary, because of the loss of some of the heavier fractions with the lighter ones.

METHODS OF BLENDING.

Blending condensate with the various distillates used for that purpose, as practiced at present, is done at times in stages, and at many different points in the precipitation, storage, or transportation of the product.

The product of plants that ship their condensate without being blended usually goes to refineries or blending stations belonging to purchasers of this type of product, who blend the condensate before sending it to the retail markets. One blending company in West Virginia buys condensate, pumps it to the plant in pipe lines, stores it in closed tanks until needed, then blends it with naphtha in the following manner:

A tank car of naphtha is one-half unloaded, usually into an empty tank car, and then condensate is slowly pumped in through a valve in the bottom until the tank is filled. The condensate rises through

the naphtha and slightly agitates it, and in this way becomes absorbed and blended with the naphtha. At times the operation is reversed, a tank car being half filled with condensate and the naphtha pumped in from above. No further treatment is used, the car being shipped as soon as filled. The agitation during shipment tends to complete blending if such is necessary.

Blending practice at some refineries and casing-head gasoline plants is practically the same as described above except that stationary tanks are used in place of tanks on cars. At other blending plants a pump is used in blending, its suction being connected with two tanks, one of blending stock and the other of condensate. The flow of each is regulated in the pipe line by valves, the discharge of the pump going to a storage tank. From time to time the mixture in the storage tank is tested for gravity, if the blend is too light or too heavy the flow of either naphtha or condensate is adjusted to give the desired mixture.

At some plants methods of blending are more complicated. The procedure used by one company receiving its condensate by auto truck is as follows: A given quantity of California distillate with a gravity of 53° to 55° B. is placed in a cone-bottom blending tank, where it is washed with acid solution, caustic solution, and water; after this treatment condensate with a gravity of 72° to 82° B. is forced into the tank from the bottom. Air is then blown through the mixture to agitate it and remove the lightest fractions of condensate and dissolved gases. The mixture is tested for specific gravity, after which enough still-run California gasoline with a gravity of 58° B. is added to bring the whole to a gravity of 60° B. The blended gasoline produced by the above method and ingredients is sweet, water white, and has the following characteristics: 5.9 per cent distills over up to 140° F., the distillate having a gravity of 79.9° B.; 70 per cent distills over up to 246° F.; and 30 per cent distills over between 246° and 344° F.

Distilling this blended product in 5 per cent cuts shows it to be an exceptionally good motor fuel with none of the usual fractions missing.

While holding condensate in storage some blending companies and refineries, as well as compression-plant operators, keep the tanks containing such stock under pressure and often the tanks are insulated or housed and shaded in order to reduce evaporation by the sun and the atmosphere, one company having gone to the expense of building a louver tower over the tanks and keeping small sprays of water constantly covering them. The tanks, which are held under pressures of 10 to 20 pounds, are set in a concrete or wooden basin. The water collects in this basin, thence it is again circulated over the tanks by pumps. No outside cooling of the water is resorted to, the

evaporation from falling through the tower and over the tanks being sufficient to keep the water at a temperature considerably below that of the atmosphere, also any volatilization of the condensate itself tends to cool the liquid.

Where blending is done by refining or blending companies, as has been described, the operation is complete and the blended product is ready for market. The blended gasoline made in the Eastern fields has a gravity of between 65° and 70° B., and that made in California between 58° and 63° B. The difference in gravity is due to differences in the character of the crude oils from which the condensate and the blending stocks were made; this variation is discussed in later paragraphs. The blending is usually done so as to bring the product to a given gravity by the mixture of the two ingredients, whereas the final end point is determined by, and is the same, as the end point of the naphtha used. Although the proportions vary under these conditions, the proportions to be mixed to make a product of a given gravity can be approximately calculated from the gravity and the end points of the two liquids.

The methods of disposal of condensate mentioned are found mostly in California and some eastern districts; with few exceptions the practice in the Mid-Continent field is to blend either at the compression plant or at the loading station operated in conjunction with the plant.

BLENDING BY PLANT OPERATORS.

When the blending is done by the operator of the compression plant, one of the following methods is generally adopted: (1) Blending all of the condensate at the blending station or loading racks; (2) blending to a given stage at the plant, and transferring the partly blended product to the loading racks and either finishing the blending there or shipping it to some point at which naphtha is cheaper or more readily obtained; and (3) completing the entire operation at the plant.

BLENDING AT THE LOADING RACKS.

Many of the companies controlling two or more compression plants, situated in the same field and tributary to the same shipping point on a railroad, have adopted the method of blending the products from all their plants at a central station. A centrally situated loading station with racks and tanks (see Plate XII, *A*, p. 52), is necessary in any event for storing and loading the plant products and unloading and storing the blending stocks, so that the stations can be also fitted for blending practically without additional cost of labor and small increases in tankage.

In stations used in this way, the usual equipment consists of tanks of any desired capacity for the storage of naphtha, other tanks for

the storage of condensate, and tanks for the blended stock and from which the marketable product is transferred to tank cars for shipment.

The plant condensate is pumped or forced by its own pressure through small pipe lines into the condensate storage tanks, and the naphtha from tank cars is pumped into the naphtha tanks. From the naphtha storage tank a given quantity of naphtha is first pumped into the blending tank, then condensate is forced into the blending tank at the bottom, being allowed to rise through and be thoroughly absorbed by the heavier naphtha. When the predetermined quantity of each stock has been mixed in the blending tank, samples are tested for gravity, and if any change in gravity is desired more of the heavy or light stock is added, as the tests indicate to be necessary. The blended gasoline is next tested for vapor tension, and, if if it found to be too high for shipment in the cars used (standard or insulated tanks), the tank is allowed to stand open to the atmosphere for several hours, or even days, if necessary. In some plants it has been found necessary to heat the blended products to 80° to 90° F. with steam, in order to reduce the vapor tension to the required point in a limited time, so that the blending could continue without the installation of an excessive amount of tankage. Heating with steam should not be resorted to if avoidable, as a quick rise in temperature drives the lighter condensates off rapidly, carrying with them portions of the heavier and less volatile fractions. When the specific gravity and the vapor tension have been brought to a point within the regulations governing shipments of gasoline, the contents of the blending tank are either drawn off into cars for immediate shipment or pumped into a storage tank.

The blending method used at the majority of such stations usually consists merely of mixing calculated quantities of the different stocks to be disposed of and reducing the vapor tension of the mixture by open contact with the air or by slight warming with steam coils, placed in the blending tank.

The advantages of blending at loading and storage stations are that the productions of a number of plants can be handled, close connection with railroad service, and the low cost of handling both the naphtha and the blended stock. At times the tank cars are used as blending tanks, as described in a previous paragraph.

PARTIAL BLENDING AT PLANT.

Some operators, because of the plant being in a place where it is difficult or costs too much to bring in large quantities of naphtha, or, more often, because the company controls a refinery and desires to refine the gasoline by further treatment, such as distilling, have adopted the practice of blending only so far as is necessary for shipment at the compression plant or blending station, the final blending

and treatment being given at the refineries or points where the desired quantities and qualities of distillates may more readily be obtained. Some operators blend partly at the plants and finish the operation at the blending station or loading racks as described above, thus saving the costs of handling, of pipe line, and of the pumping capacity necessary to transfer all of the heavy blending stock to the plant and back to the loading station.

When the blending is completed at the blending station, it is done in the way described, except that smaller proportions of heavy naphtha are added, because some heavy naphtha has been previously added to the condensate at the plant.

PLANT BLENDING METHODS.

Plants at which blending is entirely or partly completed have developed methods and practices quite different from the usual way of mixing the two constituents in a blending tank. Many plants still blend the condensate and the naphtha in storage or blending tanks, using the methods previously described above, but a tendency has developed for blending at much earlier stages of the process.

BLENDING IN "MAKE TANKS."

The first step in this development was when certain operators pumped blending naphtha into the tanks known as "make tanks" (see Pl. IV, *C*, p. 26, and XII, *C*, p. 52), which receive the condensate from the accumulator tanks, and in which the total make of one day or shift was measured before being transferred to storage. The method as now used is to pump naphtha into the tank at such a rate that the percentage in the mixture would be somewhat below that desired in the final blend, or to place a given quantity of naphtha in the make tank and discharge condensate from the accumulators into the naphtha. In transferring condensate from the accumulator tank to the make tank, the sudden release of pressure causes violent weathering or boiling, owing to the high vapor tension. By adding heavier blending stocks at this point the vapor tension is lowered, with consequent lessening of losses from the light condensate and dissolved gas weathering rapidly and carrying off with them part of the heavier fractions.

The product of this blend is gaged in the make tank, the quantity of naphtha deducted, and the actual plant production calculated. At the end of each day or shift the mixture is transferred to storage tanks and the blend completed or shipped to another point for blending as described above.

BLENDING IN ACCUMULATOR TANKS.

Blending in accumulator tanks, as found in practice by the writer, consists of pumping naphtha slowly and continually into the tanks, connected with the high-pressure coils, at a pressure a few pounds in

excess of that at which the gas is being treated. The naphtha is injected into the tank through small (½-inch) pipes at a point near the top and through fittings which cause a spray, the theory being that the spray will collect fine particles of condensate in falling through the gas and reduce the gravity and the vapor tension of the product before it is released from the high pressure at which it is precipitated and thus reduce losses of condensate.

Operators using this method claim it produces a marked increase in plant production, one in particular claiming a net increase of 10 per cent. The mixture is drained from the accumulator tank as in other practice, either automatically or by hand, as the custom of the plant may be, the quantities being figured as previously described to determine the plant production.

HOT BLENDING.

When naphtha is injected into the high-pressure gas while it is in the coils, or before it has reached the coils, and is still hot from compression, the method is called "hot blending."

This method has been adopted at some plants where the gas treated contains large proportions of the exceedingly light fractions and the condensate had shown extreme losses in storage and during weathering and blending by other methods. A Pennsylvania operator producing condensate with a gravity of 92° to 95° B. claims a net gain of 15 per cent in marketed condensate from the use of this method, and one in Oklahoma, approximately 30 per cent.

Hot blending has been tried out at two California plants, in different fields, to the writer's knowledge and no advantage gained. The plants produce condensate with a gravity of 82° to 86° B., using pressures between 200 and 250 pounds.

One eastern plant, which compressed the gas to 300 pounds pressure, injects naphtha through a needle valve placed in the high-pressure water-cooled coil header at the intake (hot) end of the coil. The naphtha is pumped through the valve at a pressure of 400 pounds per square inch, which causes it to spray or atomize in the header and intimately mix with the hot gas as the gas divides into the coil pipes leading out of the header. The first few (10 to 15) feet of this coil is kept dry to permit the hot gas to vaporize as much of the naphtha as possible before the gas and the naphtha are cooled by the water sprayed over the rest of the coil.

What happens to the injected naphtha is not definitely known, but it appears that the naphtha is divided into three parts. One part is volatilized by the heat of the high-pressure gas (190° F. on the day of the writer's visit), carried with the gas into the water-cooled coils, and again condensed, thence it is carried to the accumulator tank with other condensate. A second part of the atomized naphtha is probably carried mechanically into the upper pipes of

the coil by the flow of gas, where it settles out, owing to the slower rate of flow, and carries with it other condensable vapors. The third part, which is neither vaporized nor carried mechanically into the upper members of the coil, goes to the bottom of the header and flows with the gas through the bottom pipe and blends with the condensate and naphtha in the discharge header, while still under maximum pressure. The mixture then flows to the accumulator tank and thence is trapped into storage tanks.

The quantity of naphtha injected into the header is calculated to be somewhat less than is needed to bring the mixture to the gravity desired, the balance being added, in this plant, to the partly blended stock in the make tank, which is also held under pressure. Another feature of the practice at this plant is that the pressure on the blended stock is reduced slowly to avoid violent boiling or weathering. This is accomplished by holding a pressure of 50 or 60 pounds on the make tank while the output of the plant is being transferred to it during a day or shift. At the end of that period another tank is put into service and the pressure on the tank containing the day's "make" is slowly relieved, while the stock gradually acquires approximately the temperature of the atmosphere. At this point the blend is transferred to storage tanks or placed in tank cars for shipment. For each 100 gallons of condensate produced 77 gallons of naphtha is pumped into the coils, which lowers the gravity of the condensate from 90° to 96° B. to between 70° and 76° B.; later, in the "make" tank, enough eastern naphtha, with a gravity of 58° to 60° B., or California distillate, with a gravity of 48° B., is added to form a blend of the desired quality.

At another plant a practice similar to the one just described was adopted, except that the naphtha was injected into the hot-gas line at a point just beyond the oil separator and 40 or 50 feet ahead of the coils, the naphtha thus traveling with the gas through the coils and on to the accumulator tanks. This plant, although making 9 gallons of condensate per thousand feet of gas treated, as measured in the accumulator tanks, had by the old method of blending been able to market only 2.5 gallons. By the adoption of hot blending it was able to market 3.7 gallons from each thousand feet of gas treated. The loss, however, is still extremely high, and it is probable that an entire readjustment of pressures and temperatures throughout the plant would show better returns and smaller losses.

POSSIBLE IMPROVEMENTS IN BLENDING METHODS.

No set of rules can be given or standard methods of blending described that would even approximately cover all conditions, but there are methods and practices that if adopted by individual plants would have marked advantages and show a decided saving of condensate.

The problems of each plant must necessarily be taken up separately and a study made of the properties and characteristics of the condensate formed, such as the gravity, the vapor tension, and the proportions of the different "cuts" and the hydrocarbons they contain. That these vary widely is shown by the different pressures and temperatures necessary to precipitate the condensates, also by the vapor tensions or wildness of different plant products. The point at which blending is done should be given attention, to find whether the best results are obtained by blending in storage tanks, in make tanks, in accumulator tanks, or in coils, also the effects of release of pressure and rise in temperature should be studied to find whether sudden lowering of pressure and rise in temperature does not cause undue losses. Blended products are at many plants placed in storage tanks which are not protected from the sun and a quick rise in temperature is to be expected. The color an exposed tank is painted, has a direct bearing on the amount of heat absorbed from the sun's rays and taken up by the contents. Releasing the pressure on the condensate slowly, or holding it under a low pressure and storing it in insulated tanks has, at a number of plants, been found to decrease losses.

Refining companies have found that storing the lighter distillates in tanks with the water-sealed top, painted glossy white, show reduced losses well worth the expense of construction and operation of this system of storage.

LOSSES OF CONDENSATE IN WEATHERING AND SHIPPING.

Plant operators, in reporting losses of condensate, often use as a basis the total amount of condensate collected and measured in the accumulator tanks before blending, and while still under pressure, which is obviously the wrong place to make such an estimate, because such measurement is taken during treatment and not at the final stage of production. The condensate in the accumulator tank, because of the temperature and pressure, contains some dissolved gas and fractions of the hydrocarbon group which it is impossible to hold under normal atmospheric conditions, and which should not be counted as loss when computing the plant production.

The writer, in order to form an accurate idea of the losses at different plants, and as far as possible to use the same basis in estimating these losses, has obtained from the plants listed the quantity of condensate actually stored in tanks, either blended or unblended as the practice indicated. With this quantity as a basis estimates of the losses in further operations, such as weathering, pumping to loading stations, loading in cars and shipping, are computed.

In Table 2 (p. 29), the column headed "Daily production, gallons," represents the number of gallons that were actually marketed by the different plants listed, as nearly as these figures could be arrived at, and is net production after all losses are deducted.

CALIFORNIA PRACTICE.

California plants, in general, trap or blow the product of the accumulator tanks directly into storage tanks without blending and measure the make in the storage tanks. As these tanks are seldom held under pressures greater than 5 to 15 pounds, weathering goes on continually and causes an unknown loss, only the weathered product being measured.

At plants where the raw condensate is pumped from the storage tanks into the crude oil storage tanks of purchasing companies, under this method of calculating losses the results show no loss except that due to weathering while the condensate is being held in plant storage, the product being sold on the gage readings taken in the storage tank at the compression plant.

Companies shipping raw condensate in automobile trucks distances of 2 to 40 miles report losses in loading, transportation, and unloading of 2 to 7 per cent. Those delivering their product through pipe lines 1 to 40 miles long report losses of 1 to 6 per cent, depending on the length of the lines, the amount of leakage from them, and the pressure necessary to force the liquid through.

EASTERN PRACTICE.

Many plants in the eastern fields ship raw condensate by pipe line and trucks, as in California practice, with losses the same or slightly greater in amount than those quoted, owing to the raw products having higher gravities and vapor tensions. One large oil company has recently laid pipe lines to a number of the fields in northern and western Pennsylvania for the purpose of collecting the raw condensate produced in those fields and which was formerly hauled to market in trucks. Well-constructed pipe lines will undoubtedly minimize losses from handling condensate produced in this district.

OKLAHOMA PRACTICE.

Casing-head gasoline producers in Oklahoma estimate the total loss as varying between 10 and 40 per cent. The losses during weathering of the blended product run from 10 to 20 per cent, depending on the gravity of the raw product and the vapor tension of the blend. Often heating with steam is necessary, before loading the condensate into tank cars, to bring the vapor tension within the limits required by the railroad shipping rules, especially in cold weather, when weathering will not bring the blended stock to the desired condition.

The loss in this field due to transferring the product from the plant storage tanks to loading or blending stations varies from 2 to 7 per cent, and in loading from a rack to cars, between 1 and 5 per cent.

The loss during shipment in standard tank cars is variously given as being between 2 and 10 per cent, with an average of approximately 6 per cent, the loss depending much on the distance and length of time used in haulage, the atmospheric temperatures encountered, and the condition of the tank used for shipment.

The so-called thermos cars, an insulated tank car, have given very satisfactory returns on their cost to certain producers using them, who report a maximum outage (loss in transit) of 2½ per cent when used for long shipments in hot weather, and report instances of no outage on short hauls in moderate, rainy, or cold weather. The railroad rules governing shipments in insulated cars are more in favor of the shipper in regard to vapor pressures, allowing 15 pounds as the maximum in place of 10 pounds as in standard cars.

The losses in blending and shipping in the Mid-Continent field may be generalized as follows:

	Per cent.
Weathering	5 to 20
Transferring to loading station	2 to 7
Loading in car tanks	1 to 5
Shipping in standard cars	2 to 10
Total losses	10 to 42

Plants treating gas that contains large proportions of the lighter fractions and using pressures and temperatures that will precipitate these fractions produce the "wildest" condensate and in consequence suffer the greatest losses. As the converse of this practice a single-stage plant (No. 76 in the tables) in the Mid-Continent field, mentioned in several places throughout this paper, produces a condensate having a gravity of 79° B. and a vapor tension of about 5 pounds that is shipped in standard tank cars with a total loss of 2 to 3 per cent, including the losses from being transferred several miles through pipe lines to the loading racks and from loading into the cars.

NAPHTHA USED AS BLENDING STOCK.

To form an ideal motor fuel, the distillate or naphtha used in blending should be one that will give the mixture a uniform series of fractions between the temperatures at which distillation begins and finishes, with none of the fractions with boiling points so high as to cause incomplete combustion and carbon deposits in motor cylinders.

To blend and weather condensate to correspond with the above conditions is possible, but such practice, because of the great waste and expense, is followed only in blending special gasolines for engine or speed tests. Also, in making straight refinery distilled gasoline, because of the increased demand for motor fuel, more and more of the heavier distillates have been cut into the motor-fuel fractions, causing a lower gravity and a higher end point.

Rittman, Dean, and Jacobs [a] have shown clearly the differences in still-run and blended gasolines (see fig. 13) as they are put upon the market. They state that the blended casing-head products have larger percentages distilling below 50° C. but have longer distillation ranges, which tend to make the slope of the temperature-percentage curves for these gasolines flatter than those of straight refinery products. They also state that any gasoline having an unusually large distillation cut below 50° C. and with considerable-percentages distilling within the temperature ranges of 150° to 175° C. and 175° to 200° C., and being deficient in constituents boiling at intermediate

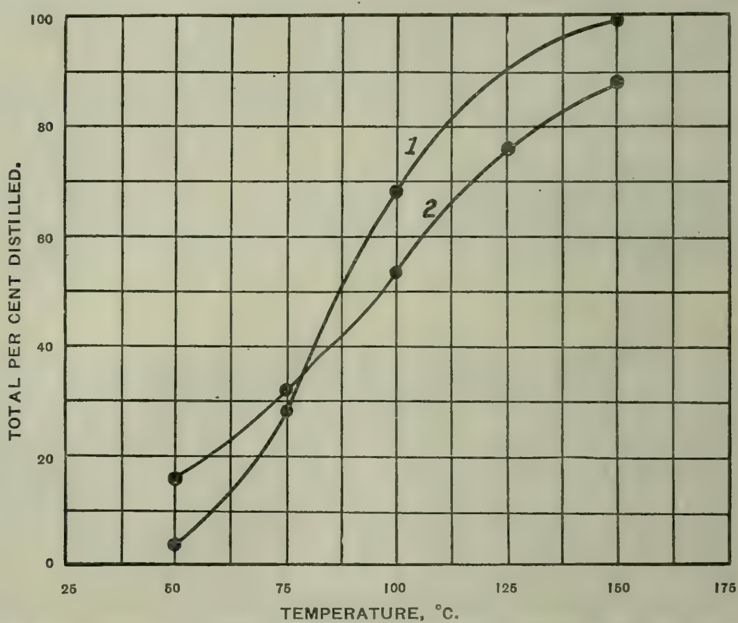


FIGURE 13.—Curves showing volatility ranges of refinery and of casing-head gasoline. *1*, refinery gasoline; *2*, casing-head gasoline. The flatter slope of the curve for casing-head gasoline shows that the content of both low and high boiling constituents is greater in the blended gasoline. After Rittman.

points of the distillation, may be classed as one of these blended products.

The naphthas or distillates being used for blending are those fractions that distill from crude oil after the cuts marketed as "straight still-run" gasoline have distilled off. The naphthas made from eastern and Mid-Continent crudes range in gravity from 46° to 60° B., whereas those made from the asphaltic base California crude oils range between 42° and 52° B. The difference in the eastern and western distillates is due to the fact that the crude oils in the different fields differ in character, having paraffin, asphaltic, or mixed bases.

[a] Rittman, W. F., Dean, E. W., and Jacobs, W. A., Physical and chemical properties of gasolines sold throughout the United States during the calendar year 1915: Tech. Paper 163, Bureau of Mines, 1916, p. 27.

The eastern and the California naphthas used in blending have approximately the same end points, although the gravities differ 7° to 10° B.; also the blends formed have different gravities, although the end points, power developed per gallon, and the completeness of combustion of the mixtures are practically similar. The differences in the specific gravities of the various cuts of similar end points from the different crudes decreases as the cuts become lighter.

Mid-Continent crudes having mixed bases vary between California and Pennsylvania crude, and have gravity and end point ratios between the two extremes stated above.

Certain companies in buying blended gasoline specify that the product shall have a gravity of not less than 67° B. and an upper end point not more than 400° F., which will require that naphtha with a gravity of about 55° B., if from Mid-Continent crude, or 48° B., if from California, be used in making the mixture.

Numerous blending plants, however, use distillates with as low gravity and as high end point as the kerosene fractions, and, as far as is known, find no trouble in marketing such blends. In using naphthas for blending it has been found that the heavier naphthas give better results than the lighter ones in lowering the vapor tension of the mixture, for equal quantities put in, the heavy fractions having a tendency to "hold down" the light fractions.

PROPORTIONS IN BLENDS.

In general it may be stated that blended gasoline usually consists of a mixture of half casing-head gasoline and half naphtha or distillate, but the proportions vary, depending upon the gravity and vapor tension of both constituents, blending being carried to a point, in conjunction with weathering, that brings the product within the shipping rules and shows maximum profits to the producers.

STRATIFICATION OF BLENDED GASOLINE.

In many quarters belief has been expressed that in blended gasoline the light condensate fractions separate from the heavier distillate fractions, causing stratification. The writer could find no direct evidence that such stratification takes place, and interviewed many operators and blenders who had made various tests and were unable to find such a condition. It is true that owing to change of temperature, in a closed tank, the lighter fractions at times vaporize and condense on the sides of the container and drain down, floating in a thin layer on top of the liquid. This condition may have given rise to the belief regarding stratification, but, as shown, is not due to separation of the two or more blended constituents through differences in their gravities. All fractions of petroleum oils are gen-

erally considered as soluble, one in the other, and a blend of two or more fractions such as naphtha and condensate should not separate or stratify. All evidence obtainable indicates that no such stratification actually takes place in blended motor fuels through the difference in specific gravity of the members blended. A test made on a California blended product and reported to the writer showed no separation. The blend, which was a small quantity of condensate with a gravity of 105° B. and a large quantity of distillate with a gravity of 48° B., was placed in a 10-barrel tank and tested after standing one week without being disturbed. Samples drawn from the top and bottom had specific gravities differing only 0.07° B. This blend found a ready market as fuel for motor trucks.

The naphthas used and the blends marketed at the present time depend to no small extent on the market conditions of the heavier distillates. Naphthas that can be obtained in quantity easily and regularly, thus insuring a steady supply, are often chosen in preference to a more perfect blending stock, supplies of which can not be depended upon.

COSTS OF COMPRESSION PLANTS.

The widely varying conditions under which compression plants are being installed, both as to situation and the machinery and the steel markets, make estimates of the costs of plants so uncertain that the subject will be undertaken with the idea of showing the costs of plants recently installed, of which the writer has knowledge, rather than to attempt to estimate costs in general for present or future installations.

An operator in the Mid-Continent field who has built and is running three plants computes plant construction costs on a unit basis and gives the costs of one unit that will treat 400,000 to 500,000 cubic feet of gas daily, as follows: One single-stage unit, compressing the gas to a pressure of 75 or 90 pounds, $8,000 to $9,000; one two-stage unit compressing to 200 or 250 pounds, $15,000 to $18,000. Vacuum pumps at the compression plants are included in this estimate, but not gathering lines with their pumps, or the expansion engines that are used at the plants. On this basis, a 1,000,000-foot plant compressing gas to a pressure of 250 pounds would cost approximately $36,000, or $36 per 1,000 feet of capacity.

The expense of construction and equipment of a plant compressing 1,250,000 cubic feet of gas daily to 250 pounds, put into commission in June, 1916, was stated to be $36,570, divided as follows:

Cost of compression plant with a capacity of 1,250,000 cubic feet.

Machines, engines, compressors, water pumps, and air pumps and tanks	$18,240
Pipe and fittings, engine and compressor connections, cooling coils and double-pipe coils	1,534
Building compressor room with steel frame, cooling tower, accumulator tank and storage housing, auxiliary engines and pumps	6,756
Gathering lines	3,797
Tankage	1,105
Gas traps	700
Electric plant	395
Labor, carpenter work; pipe-fitting; concrete, etc.; setting engines	4,043
Total	36,570

No expansion set is included in this estimate, but when the capacity of the plant was doubled later in the same year a simple single-stage compressor was installed as an expansion engine and is used to expand all of the gas treated, or 2,500,000 cubic feet. The construction of the first half of the plant shows a cost of $29 per 1,000 feet capacity. The entire cost of the plant after the original capacity was doubled and an expansion engine installed is approximately $60,000, or $24 per 1,000 feet capacity.

Another plant with a total capacity of 2,500,000 feet, built during the same period, using the same pressures and very similar to the plant described above, in units and "hook-up" (compressor and engine drive), but using a drilling engine as an expander, cost $55,000, or $22 per thousand feet capacity.

The cost per 1,000 feet of capacity of plants treating small quantities of gas, 100,000 to 250,000 cubic feet daily, is relatively higher; instances having come to the attention of the writer of costs of $40 or $50 per 1,000 feet capacity for plants of that size.

One small plant—a 250,000-foot plant compressing gas to 250 pounds—including an expansion engine, cost $11,000, or more than $44 per 1,000 feet of capacity.

Plants treating small quantities of gas under pressures obtained by single-stage compressors and having simple cooling systems, such as are found in many eastern fields, notably Sistersville, W. Va., cost much less than is indicated by the above estimates.

No estimate of costs of gathering systems, with vacuum stations and booster compressors, can be made, as the conditions vary from a few hundred feet of 6-inch lines to lines of 8 and 10 inches diameter extending 5 to 10 miles from the plant and having as many as 30 pumps and "booster" machines forcing the gas through the mains and maintaining low pressures on the wells.

MINIMUM PLANT CAPACITY AT WHICH GAS CAN BE TREATED PROFITABLY.

The question of how much gas is necessary to make the installation of a compression plant profitable often arises. This subject is approached more easily and clearly from the point of production, the quantity of gas being allowed to vary accordingly. Operators owning wells producing enough gas to produce 150 or more gallons of condensate daily can at the present price of that product well afford to install a plant, provided that no royalties have to be paid, that the gas will yield 1 gallon or more per 1,000 cubic feet, and that not more than one extra man must be kept on the pay roll. To produce this quantity of condensate under these conditions, 150,000 cubic feet of 1-gallon gas, or 50,000 cubic feet of 3-gallon gas would be profitable. In plants of this size owned and operated by oil and gas producers, often no extra help is needed, the plant being watched and taken care of by pumpers in making their regular rounds of the lease. The cost of such plants varies under average conditions between $4,000 and $8,000, and profitable returns on the costs of installation are shown.

With these costs as a basis and considering royalties and additional labor to run the plants, the quantities and richness of gas necessary to make an installation profitable may be estimated. Many small plants in the eastern fields are treating 75, 000 to 100,000 cubic feet of gas daily, and the fact that they continued to run during times when condensate sold at 8 and 10 cents per gallon would indicate that profits under the present conditions are gratifying. The price received in August, 1916, at Sistersville, W. Va., for condensate with a gravity of 86° B., was reported to be more than 18 cents per gallon.

PLANT RECORDS.

The writer in collecting detailed plant data found that many, in fact most compression plant operators used no system of daily report sheets or records of plant operation further than making each day an estimate of the condensate produced. It is difficult to see how plants of this character can be operated intelligently, or improvements made, unless accurate records of all the more important plant functions are carefully kept and used in directing changes and experiments to improve the practice and increase the quantity and quality of the product. At fully one-half of the plants visited no attempt was made at keeping data of any kind excepting records of the production, and only a limited number of those keeping accurate and detailed records made any use of them; or had tried to improve either the operation or the product. For instance, the pressure of 250 pounds is almost universally used as the ultimate pressure at plants throughout the western fields, because other operators use

it and because the machines and pipe fittings are designed for that pressure, the actual qualities of the gas being treated not being considered. At one plant that had been using a pressure of 250 pounds, it was found that the engines gave less trouble when the pressure was reduced to about 200 pounds and that no less condensate was produced, showing that the higher pressure had not been used because it was best suited to the gas but because it was standard for the machines in use.

In every plant the best pressures and temperatures to use must be found by trial and experiment, but without records of results and conditions improvements will be slow in coming. The accompanying form shows the daily report sheet used by a progressive California operator. Many of the records are made by recording gages and thermometers, the charts being filed for reference and comparison with the report sheet. At any sign of a disturbance of any plant function, additional information is gathered, such as the specific gravity of the gas before entering and after being discharged from the plant and after each step in its treatment. The quantities of condensate precipitated and collected at each accumulator tank and its specific gravity are also found useful in locating plant disturbances or irregularities. Records of temperatures of the gas, at each change of pressure and after each set of coils is passed or each fraction of condensate is removed, should be kept. Records of cooling water and atmospheric temperatures, in conjunction with other records, may show either the cause or the effect of changes in the gas or in plant conditions. Although the cooling of gas in coils and of water in towers has been practiced for years, many casing-head gasoline plants have installed only the most primitive and least efficient systems, and the lack of records and data obscure the fact that poor results are being obtained from their use.

Records of engine speeds and other purely mechanical data, such as the number of hours machines are shut down and the reasons for such delays, are of use in determining costs, plant efficiency, and the efficiency of men in charge of plants or the machines, as well as the principal causes of trouble and weakness of any machine or part.

Accurate plant records are also valuable in cooperating with operators of other plants in an endeavor to improve general plant practice and operation. It was noticed in districts where friendly cooperation existed that the practice in general in that district was more modern and that the operators and men in the plants had a broader understanding of the process as a whole.

The measure of success in most compression plants has been considered only from a narrow viewpoint, the improvements possible and the waste of condensable vapors contained in the gas being overlooked.

Report sheet used at compression plant in California.

Date ....

DAILY REPORT. On tour .... First engineer .... Third engineer ....

Gasoline Plant C, No. 1. Off tour .... Second engineer .... Fireman ....

Gas from wells No. ....

MACHINE REPORT.

Shut Downs.	Number of machine.																			
	1		2		3		4		5		6		7		8		9		10	
	Hours.	Minutes.	Hours.	Minutes.	Hours.	Minutes.	Hours.	Minutes.	Hours.	Minutes.	Hours.	Minutes.	Hours.	Minutes.	Hours.	Minutes.	Hours.	Minutes.	Hours.	Minutes.
For shift .... For month forwarded .... Total for month																				

Speed—Revolutions per Minute.											
Machine No.		1	2	3	4	5	6	7	8	9	10
Time of reading	3 6 9 12										

Oil Used—Gallons.				
	Steam cylinder.	Journal.	Compression and gas cylinder.	Glycerin.
For shift .... For month forwarded . Total for month .... Total for year				

GAS TEMPERATURES—DISCHARGE FROM LOW AND HIGH PRESSURE CLYINDERS.

Machine No.		1		2		3		4		5		6		7		8		9		10	
		Intermediate.	High.	Intermediate.	High.	Intermediate.	High.	Intermediate.	High.	Intermediate.	High.	Intermediate.	High.	Intermediate.	High.	Intermediate.	High.	Intermediate.	High.	Intermediate.	High.
Time of reading	3 6 9 12																				

		TEMPERATURES AND PRESSURES.						EXPANSION SET—TEMPERATURES AND PRESSURES.													
		Atmospheric temperature.	Cooling water.	Scrubber.		High-pressure inlet.		Intermediate expansion.		Discharge to lease.		Bess. coil No. 1.		Coil No. 2.		Coil No. 3.		Number of coils cooled by intermediate expansion.	Number of coils cooled by low-pressure expansion.
				Pressure.	Temperature.	Pressure.	Temperature.	Pressure.	Temperature.	Pressure	Temperature.	Inlet.	Outlet.	Inlet.	Outlet.	Inlet.	Outlet.		
Time of reading	3 6 9 12																		

PRODUCTION REPORT.

	Gallons.	Gravity.		Gallons.	Gravity.		
Low pressure High pressure Coil 1 Coils 2 and 3 Exhaust			For shift For month forwarded. For month total For year forwarded For year total			Boilers cleaned Boilers repaired Furnace repaired Water used	

REMARKS:

Certified correct by .... First Engineer.

Sheet No..........

The staff of the Bureau of Mines receives many letters asking information regarding the manufacture of gasoline from natural gas, which they willingly and gladly answer, but in most of these letters the data regarding both the gas and the operation of the plant are so meager that answers must be of a very general character and are probably as unsatisfactory to the correspondent as to the writer.

SUMMARY.

In the following paragraphs some of the more important factors relating to natural-gas gasoline and its production by the compression process are briefly discussed.

TESTING NATURAL GAS TO DETERMINE ITS SUITABILITY FOR MAKING GASOLINE.

The various hydrocarbons, and also the impurities, found in natural gas as it comes from oil or gas wells, have a direct bearing on the plant practice and treatment that will yield the most condensate. The more complete and thorough the tests made on the gas to determine its composition and physical characteristics are, the less chance there will be of those interested building and operating a compression plant that is not best suited for treatment of that particular gas.

Thus far the plants installed have been generally of standard design and equipment using the maximum safe pressures for which standard machines and fittings were built and temperatures obtainable by simple methods of water cooling, little consideration being given to the qualities of the gas to be treated.

Gas testing as followed at the present time is done only to determine if the gas can be profitably treated, and, if found so, a plant of general standard design is put in operation. It must be admitted that these plants as a whole, throughout the United States, have proved financially successful, but as a rule such success is due, in the writer's opinion, more to the fact that only the rich gas has been taken for treatment than to careful plant design and operation. The great increase in production at a few of the plants where the operators have studied the gas being treated and installed equipment best suited to its composition and characteristics indicates that gross waste is taking place at many plants of standard design. As more is learned of the best methods of treating natural gas in compression plants, gas of lower gasoline content can be and will be used in such plants.

At many plants visited no gas tests of any kind had been made since the original tests to determine whether the gas was rich enough in gasoline to warrant treatment. With the aging of the wells, the extension of gathering lines, and the installation of vacuum pumps, which often draw air into the gas lines, it is hard to believe that no variation in treatment was necessary if the best results were desired.

Gravity tests of the gas used should be made from time to time at all plants. The results will indicate any changes in composition and usually whether air has been taken into the line. This test, if made at different points in the treatment and on the treated gas may also indicate either a change in the character of the gas or that some part of the plant is not working as usual. Other tests, such as absorption and compression tests and analyses, made and recorded at regular intervals, have been of value in determining sources of trouble and indicating the need of experiments and of plant changes.

Experimenting with the entire plant or one complete unit by changing the temperatures and pressures and recording the results may lead to better recovery or a better product.

PRESSURES AND TEMPERATURES.

Gas from wells that are being and often have been gas-pumped for years, and are held under high vacuums is composed largely of the heavier vapors that would, unless vacuums were used, remain as liquid in the oil, and in treating such gas extreme pressures and temperatures are not necessary.

In eastern fields, where these conditions are most often found, single-stage plants working at a pressure of about 100 pounds and using such temperatures as can be obtained in submerged coils cooled by the natural temperatures of well or creek waters, give satisfactory recoveries and produce condensates with a gravity and vapor pressure as high as can be handled, either blended or unblended. In the same fields, however, plants treating gas from old wells not held under vacuum have found that not enough of the vapor carried by the gas can be condensed at pressures lower than 300 pounds to be profitable. The condensate produced at that pressure was exceedingly wild and in order to effect a maximum saving required blending as early in the process of precipitation as possible. It appears from the above facts that gas taken from wells held under high vacuum carries portions of the higher-boiling fractions, distilled from the oil under reduced pressures, that would otherwise have remained in the oil in the sands. The removal of the lighter fractions by this method has less effect on the gravity of the refined oil than would at first seem probable, because a marked percentage of these vapors undoubtedly came from oil left in the sands which in all probability will never be extracted, and also because the oil production from many small wells held under high vacuums is stored for days, and even weeks, in tanks, exposed to changes in atmospheric temperature, during which time the lighter fractions are lost to a greater or less extent. Under these conditions, relieving the oil of its lightest vapors before it is exposed to evaporation, or while still in the sands underground, would save these valuable products.

In the newer fields, in which the gas is still produced under widely varying rock pressures, a maximum plant pressure of 250 pounds is almost universally used, and refrigeration has often been found to increase production 10 to 50 per cent.

Besides the usual cooling with water, at some plants the gas is also cooled in heat interchangers, while still at the maximum pressures used, with expanded gas. The dry compressed gas is expanded adiabatically in the power cylinder of a steam engine, its temperature being lowered at times to $-100°$ F. In the heat interchanger the high-pressure gas is reduced to temperatures as low as $-10°$ F., which causes vapors not condensed in the water-cooled system to precipitate. It is the writer's opinion that many plant operators are overlooking gas expansion as a means of increasing the net production of their plants.

The treatment of natural gas for gasoline is unlike those manufacturing processes in which the treated material may be stored and treated a second or third time after the first extraction or concentration of the desired portions, because the gas, after once coming to the surface, must be kept moving until treated and used as fuel or wasted to the atmosphere. Thus marketable fractions of condensate left in the gas after treatment are practically entirely wasted.

CONDENSATE.

The gasoline carried in natural gas and precipitated at different points in the treatment consists mostly of pentane and hexane, the fifth and the sixth members of the paraffin series, smaller proportions of heptane, the seventh member, and decreasing percentages, if any, of propane and butane, the third and fourth fractions. In condensates produced at high pressures and low temperatures, probably some propane and butane are present and with dissolved gas cause the high vapor tensions of some plant products. The amount of dissolved gas is probably of no importance, as far as volume is concerned, but there seems to be little reason to doubt that when the pressure on the condensate is relieved the gas has a decided tendency to cause boiling and agitation of the liquid, which, with boiling of the propane or the butane, causes losses not only of these constituents but also of some of the heavier members during weathering.

The gravity of the plant products as they come to the accumulator or the "make tanks" varies between 70° and 96° B., and the vapor tension, from 5 to 40 pounds.

The gravity and the vapor tension of the condensates as collected in the accumulator tanks of the successive stages become higher as the higher pressure and the lower temperature changes are reached. The products range from line drip or distillate with a gravity of 55° B., produced at atmospheric temperature and pressure, to condensate

with a gravity of 105° B., produced in the accumulator tank at the expansion-engine exhaust, at −40° F., the gas having been reduced to a pressure of 10 pounds.

Experiments and the equipment of recent plants indicate that to remove the condensate from contact with the gas as soon as possible after precipitation and collection is the best practice. This is accomplished by the use of small automatic traps, which drain the liquid from the accumulator tanks as soon as collected. The liquid then passes through pipes to "make tanks," or storage tanks, the pressure being reduced on a small quantity of condensate at each dumping of the trap with the least possible agitation and consequent boiling. This method reduces transfer losses and those from sudden lowering of pressure on large amounts of condensate at one time. The automatic traps are used in transferring either raw or blended products from accumulator tanks to storage or "make" tanks at lower pressures.

BLENDING.

Although some casing-head gasoline is shipped and used without being blended, most of it is mixed or blended with naphtha of lower gravity and vapor tension before reaching the consumer.

Condensate, although at times shipped unblended, is in the most modern plants and the latest practice blended as soon as possible after being formed, or even while in the process of precipitation. Some operators still ship their product partly blended or reduced in gravity and vapor tension to blending stations or refineries, but the general practice is to blend at some stage of precipitation or storage at the plant.

Blending at the plants is done in the storage tanks, the "make tanks," and the accumulator tanks, and at times in the coils while the condensate is still in process of precipitation and in contact with the high-pressure gas. Operators using these methods claim definite increases in production for each successively earlier point in the process of cooling and precipitation in the high-pressure units at which blending is accomplished.

Naphthas having an end point of approximately 400° F. are in general use as blending stocks, but at some plants where regular supplies of this stock could not be obtained, distillates having the end points and gravities of kerosene are used.

Some blending companies use with the usual naphthas small quantities of "straight" still-run California gasoline, specific gravity 58° B., and Mid-Continent and eastern grades, specific gravity 66° to 68° B., in order to increase the proportions of those hydrocarbons of which the naphtha and the condensate contain only small percentages.

THE ADVANCEMENT OF THE INDUSTRY.

Since the first commercial gas compression plants were established, about 15 years ago, in the eastern oil fields, marked advancement has been made in the mechanical and commercial phases of the natural-gas gasoline industry.

Up to about five or six years ago, most of the plants consisted of the simplest forms of gas pumps, single-stage compressors, and cooling coils, were operated only on rich casing-head gas that would produce 4 to 6 gallons of condensate, and had a capacity of not more than 200,000 or 300,000 cubic feet daily.

At present plants are in operation treating 6,000,000 to 9,000,000 cubic feet daily of gas yielding as low as 1 gallon of condensate per 1,000 cubic feet, using pressures of 250 and 300 pounds per square inch in two stages of compression, with elaborate systems of cooling the gas with water before compression and after each stage of compression. The water used is cooled below normal temperatures by induced aeration and radiation.

In some plants the gas is further cooled by expanding the dry treated gas through the cylinders of an expansion engine and using the cold expanded gas to cool the high-pressure gas from the water-cooled coils. Temperatures as low as 0° F. are often obtained, causing the precipitation of nearly all the condensable fractions commercially valuable for making gasoline.

FORMULAS AND TABLES GOVERNING THE FLOW OF GAS IN PIPE LINES.

Formulas governing the flow of gas in pipes have been worked out by Weymouth and discussed by him in a paper[a] published by the American Society of Mechanical Engineers. These formulas with that part of Weymouth's report that relates to the flow of gas in pipe lines are given in the following:

TRANSMISSION OF NATURAL GAS.

By Thomas R. Weymouth.

In the design of pipe lines for the transmission of natural gas from the field to the points of consumption it is necessary to make use of a formula expressing the relations to each other of the quantity and initial and final pressures of the gas, and the diameter and length of line. Many such formulas have been proposed giving widely differing results. In nearly all of them the flow is stated as varying as the square root of the fifth power of the pipe diameter, and either the coefficient of friction is considered constant, or a different coefficient is given for each diameter of pipe. This serves well enough where the diameter is known and any one of the other quantities expressed by the formula is desired, but is somewhat awkward when it is desired to ascertain the diameter of line necessary to meet the other given conditions.

The author has derived a new formula which he believes expresses the relationship of the quantities involved even more closely than any heretofore offered. It is based on isothermal flow, and the variation in the value of the coefficient of friction is provided for without complicating the formula, yet permitting the required diameter of line to be ascertained readily.

The expression for the initial velocity of any gas flowing in a pipe is given by Unwin[b] as

$$(1) \qquad u_1=\sqrt{\frac{gCTm}{fl}\frac{(P_1^2-P_2^2)}{P_1^2}}$$

u_1=initial velocity, in feet per second.
g=acceleration due to gravity.
C=thermodynamic constant of the flowing gas $=\frac{PV}{T}$
T=absolute temperature of gas.
m=hydraulic mean radius of the pipe $=\frac{D}{4}$.
P_1=absolute initial pressure of the gas, in pounds per square inch.
P_2=absolute final pressure of the gas, in pounds per square inch.
f=coefficient of friction.
l=length of line, in feet.

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[a] Weymouth, T. R., Problems in natural-gas engineering: Trans. Am. Soc. Mech. Eng., vol. 34, 1912, pp. 185–234.

[b] Unwin, W. C., Transmission and distribution of power from central stations, 1892, p. 259.

Let

C_a=thermodynamic constant for air.

G=specific gravity of flowing gas, air=1.0.

D=diameter of pipe, in feet.

d=diameter of pipe, in inches.

$$\text{Then } C=\frac{C_a}{G}, \text{ and } m=\frac{D}{4}=\frac{d}{48}$$

Hence

$$(2) \qquad u_1=\left[\frac{gC_a T(P_1^2-P_2^2)d}{48\ GflP_1^2}\right]^{\frac{1}{2}}$$

If q=quantity of gas flowing per second, based on absolute pressure and temperature of P_o and T_o,

$$A= \text{area of cross section of pipe in square feet} =\frac{\pi d^2}{4\times 144}$$

Then

$$(3) \qquad q=u_1A\frac{P_1\,T_o}{P_o\,T}=u_1\left(\frac{\pi d^2}{4\times 144}\right)\frac{T_o\,P_1}{P_o\,T}\left(\frac{\pi}{576}\right)\frac{T_o}{P_o}\left[\frac{gC_a(P_1^2-P_2^2)d^5}{48\ GTfl}\right]^{\frac{1}{2}}$$

If

Q= flow in cubic feet per hour, based on P_o and T_o, and

L= length of line, in miles,

Then

l=5280L

and

Q=3,600q

$$(4) \qquad Q=\frac{3,600\,\pi}{576\sqrt{48 \times 5280}}\frac{T_o}{P_o}\sqrt{gC_a}\left[\frac{(P_1^2-P_2^2)d^5}{GTfL}\right]^{\frac{1}{2}}$$

Taking g=32.17 and C_a=53.33,

$$(5) \qquad Q=1.6156\frac{T_o}{P_o}\left[\frac{(P_1^2-P_2^2)d^5}{GTfL}\right]^{\frac{1}{2}}$$

Experiments on the flow of air in pipes of different diameters indicate that the coefficient of friction f is a variable, decreasing with increasing diameters of line. A great many such experiments have been collected and published in "Compressed Air," by Elmo G. Harris, from which, by the use of equation *5*, the coefficients of friction have been computed and plotted in figure 14.

In the reports of these tests no statements were made as to the method of measuring the quantity of gas flowing, and it is quite probable that many of the results are inaccurate in this respect. Notwithstanding this, however, the nature of the variation of f with the diameter is evident, and the curve represented by the equation

$$f=\frac{0.008}{\sqrt[3]{d}}$$

gives a fair average of the loci of the points plotted. Inserting this value of f in equation *5*, the expression becomes

$$(6) \qquad Q=18.062\frac{T_o}{P_o}\left[\frac{(P_1^2-P_2^2)d^{5\frac{1}{3}}}{GTL}\right]^{\frac{1}{2}}$$

Equation *6* is the general formula for the flow of gas in long pipe lines.

In 1901 Forrest M. Towl conducted an extended test on an 8-inch line, 70 miles long, supplying gas to Buffalo, the results of which were published in a bulletin issued by Columbia University in 1911. Previous to the test the line had been repaired and tested for leaks, and was known to be practically gas-tight. The flow was measured by standardized Pitot tubes, which gave results accurate within less than 1 per cent. The specific gravity G of the flowing gas was 0.64, its temperature

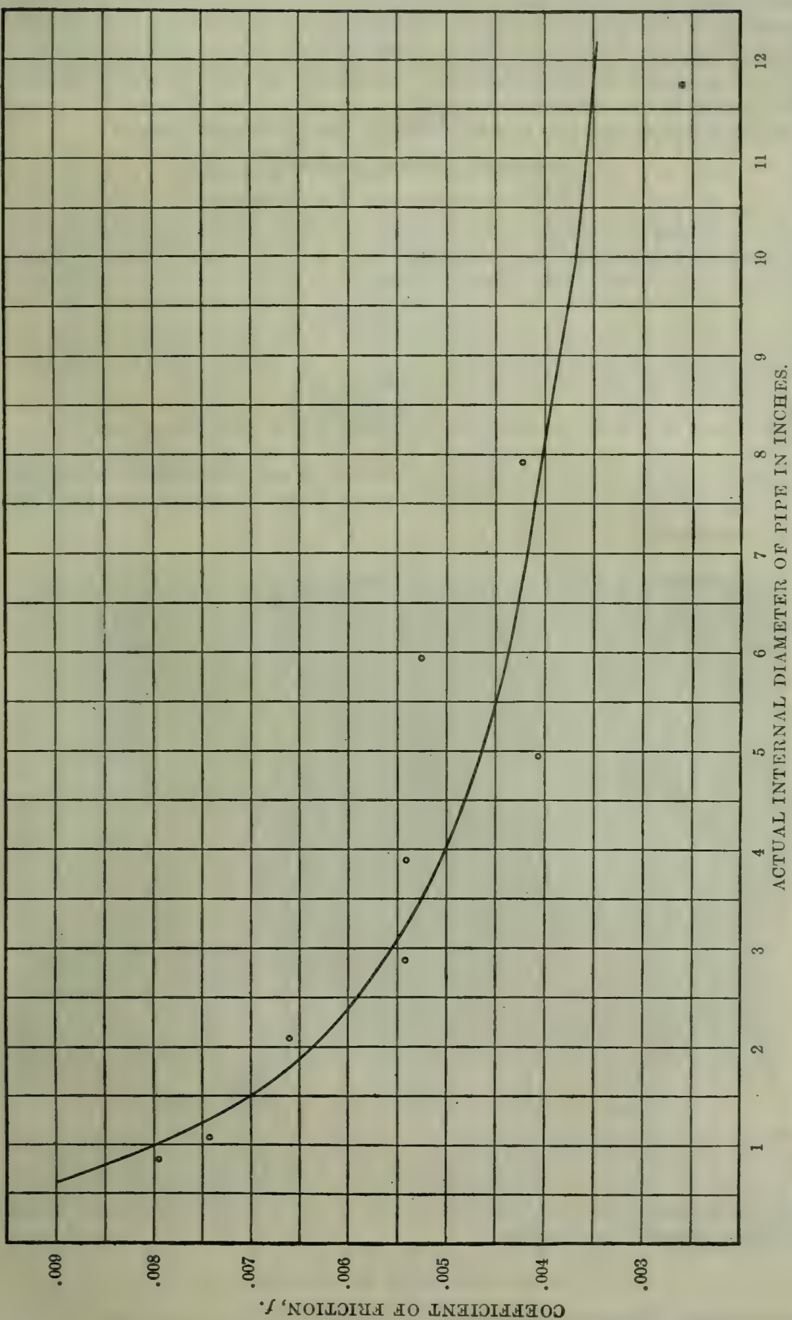

FIGURE 14.—Curve for coefficient of friction for flow of gas in pipes. Coefficient of friction f equals $\frac{0.008}{d^{1/3}}$, where d is internal diameter of pipe in inches.

32° F., or T=492° absolute. The temperature basis on which the gas was measured was 50° F., or T_0=510° absolute, and the pressure basis was 4 ounces above 14.4 pounds, or P_0=14.65 pounds per square inch absolute. In a length of pipe 70.32 miles long P_1 and P_2 were 210 and 41 pounds per square inch absolute, respectively. The actual diameter of the pipe was 7.981 inches, and the rate of flow by Pitot tube was found to be 221,000 cubic feet per hour.

Inserting these quantities in formula *1* and solving for flow, it becomes

$$Q=221{,}400 \text{ cubic feet per hour,}$$

or less than 0.2 per cent greater than the actual flow as measured.

Assuming gas standard conditions of measurement basis, namely, 60° F. and 14.65 pounds absolute pressure, and that the average flowing temperature of the gas throughout the year will be 40° F., the formula becomes

$$(7) \qquad Q=28.66\left[\frac{(P_1^2-P_2^2)d^{5\frac{1}{3}}}{LG}\right]^{\frac{1}{2}}$$

and, if an average specific gravity of 0.60 be assumed,

$$(8) \qquad Q=37\left[\frac{(P_1^2-P_2^2)d^{5\frac{1}{3}}}{L}\right]^{\frac{1}{2}}$$

Formula *8* is of practical use in designing lines for the transmission of natural gas. It is used as given, or in a transposed form, for all problems relating to single lines of uniform diameter.

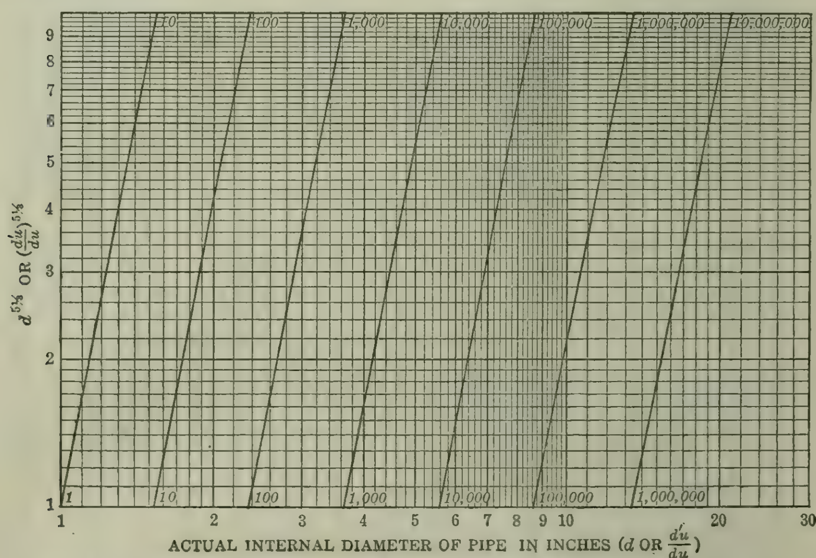

FIGURE 15.—Broken curve showing values of equivalent lengths of different diameters of pipe.

If a line is composed of several lengths, L_1, L_2, . . . L_n, of diameters d_1, d_2, . . . d_n, each of these lengths must be transformed into an equivalent length of one chosen diameter, by means of the formula

$$(9) \qquad L_n^1=L_n\left[\frac{d_n^1}{d_n}\right]^{5\frac{1}{3}}$$

These equivalent lengths added together will give $L=L_1$, L_2, . . . L_n, which is the value for L in formula *8*.

Values of equivalent lengths for different diameters can be most conveniently ascertained by the use of the curves in figure 15, which consist of plots of the values of $d^{5\frac{1}{3}}$ for varying values of d. Values taken from these curves are convenient to use directly in the pipe-line formula, equation 8, whereas they are most simply used in equation 9 as values of the $5\frac{1}{3}$ power of the diameter ratios.

TABLES.

VOLUME OF FLOW FROM DIFFERENT SIZES OF PIPE AT VARIOUS PRESSURES.

The number of cubic feet of gas of a specific gravity of 0.6 (air equaling 1.0) that will flow from the mouth of a 1-inch pipe in 24 hours is given in Table 10 following. The pressure of the container is taken as 4 ounces above an assumed atmospheric pressure of 14.4 pounds to the square inch, and the temperature of the flowing gas and the container is assumed to be 60° F. If the diameter of the pipe is other than 1 inch, multiply the discharge value given in Table 10 by the square of the actual diameter of the pipe, as found in Table 11.

TABLE 10.—*Rate of flow of natural gas in pipe 1 inch in inside diameter at various pressures.*[a]

Observed gage pressure.			Flow, cubic feet per day.	Observed gage pressure.			Flow, cubic feet per day.
Inches of mercury.	Inches of water.	Pounds per square inch.		Inches of mercury.	Inches of water.	Pounds per square inch.	
....	0.1	0.0036	12,390	10.17	....	5.0	436,200
....	0.2	0.0073	17,5[illegible]	11.18	....	5.5	456,200
....	0.3	0.0109	21,480	12.20	....	6.0	473,750
....	0.5	0.0182	27,720	13.21	....	6.5	489,840
0.05	0.7	0.0254	32,820	14.23	....	7.0	505,920
0.7	1.0	0.0364	39,210	15.25	....	7.5	522,010
0.11	1.5	0.0545	48,030	16.26	....	8.0	538,5[illegible]
0.15	2.0	0.0727	55,340	18.[illegible]	....	9.0	5[illegible]5,970
0.22	3.0	0.109	67,910	20.33	....	10.0	589,270
0.29	4.0	0.145	78,410	24.39	....	12.0	633,340
0.37	5.0	0.182	87,670	28.46	....	14.0	675,000
0.52	7.0	0.254	103,500	32.53	....	16.0	713,550
0.74	10.0	0.3636	123,000	36.60	....	18.0	748,650
1.02	13.75	0.50	146,220	40.66	....	20.0	779,350
1.52	20.62	0.75	175,350	50.81	....	25.0	845,150
2.03	27.5	1.00	201,800	61.00	....	30.0	902,180
3.05	41.25	1.5	247,840	71.16	....	35.0	954,820
4.07	55.0	2.0	285,130	....	....	40.0	98[illegible]
5.08	68.75	2.5	316,500	....	....	45.0	1,03[illegible],700
6.10	82.50	3.0	344,350	....	....	50.0	1,072,000
7.12	96.25	3.5	370,000	....	....	55.0	1,106,880
8.13	110.0	4.0	393,000	....	....	60.0	1,137,600
8.15	....	4.5	415,270				

[a] Thompson, A. B., Oil-field development and petroleum mining, Lind., 1916, pp. 578–579; quoted by Johnson, R. H., and Huntley, L. G., Oil and gas production, 1916, p. 9.

In correcting for temperature of flowing gas, where observed, of 30°, 40°, 50°, and 60° F., add 4, 3, 2, and 1 per cent, respectively. To change the result, as found by this table, to that for any other specific gravity of gas than 0.6, multiply by $\sqrt{\frac{0.6}{\text{specific gravity of gas}}}$

TABLE 11.—*Multipliers for pipe of diameters other than 1 inch.*[a]

Diameter of opening.	Multiplier.	Diameter of opening.	Multiplier.	Diameter of opening.	Multiplier.	Diameter of opening.	Multiplier.	Diameter of opening.	Multiplier.
Inch.		*Inches.*		*Inches.*		*Inches.*		*Inches.*	
$\frac{1}{16}$	0.0038	1	1.00	4	16.00	6	36.00	8	64.00
$\frac{1}{8}$	0.0156	$1\frac{1}{2}$	2.25	$4\frac{1}{4}$	18.00	$6\frac{1}{4}$	39.00	$8\frac{1}{4}$	68.00
$\frac{1}{4}$	0.0625	2	4.00	5	25.00	$6\frac{5}{8}$	43.90	9	81.00
$\frac{1}{2}$	0.2500	$2\frac{1}{2}$	6.25	$5\frac{3}{16}$	26.90	7	49.00	10	100.00
$\frac{3}{4}$	0.5625	3	9.00	$5\frac{5}{8}$	31.60	$7\frac{1}{4}$	52.50	12	144.00

[a] Johnson, R. H., and Huntley, L. G., Oil and gas production, 1916, p. 355.

TABLE 12.—*Variation in volume of 100 cubic feet (100 per cent) of gas at constant temperature under various gage pressures.*[b]

Pressure per square inch.	Volume.	Pressure per square inch.	Volume.	Pressure per square inch.	Volume.
Ounces.	*Per cent.*	*Pounds.*	*Per cent.*	*Pounds.*	*Per cent.*
0	100.0	4	78.6	20	42.3
2	99.1	5	74.6	30	32.8
4	98.3	6	71.0	40	26.8
6	97.5	7	67.7	50	22.7
8	96.7	8	64.7	75	16.8
10	95.9	9	62.0	100	12.8
12	95.1	10	59.5	150	8.9
14	94.3	12	55.0	200	6.8
Pounds.					
1	93.6	14	51.5	250	5.5
2	88.0	16	47.8	300	4.6
3	83.0	18	44.9	400	3.5

[b] Johnson, R. H., and Huntley, L. G., Principles of oil and gas production, 1916, p. 355.

CHANGE IN VOLUME OF GAS WITH CHANGE IN TEMPERATURE.

In Table 13 following, the standard is taken at 60° F. and 14.4 inches of mercury plus 0.25 = 14.65 inches of mercury. Absolute zero = 460° F. below freezing = 488° below 60° F. The specific gravity of the natural gas is taken at 0.6, air being 1. The same 1,000 cubic feet of gas at 60° F. will measure 1,041 cubic feet at 80° and 959 cubic feet at 40°. The percentage of the decrease and increase below or above 60° F.; the specific gravity of the gas at temperatures below and above 60° F.; also weight of 1,000 cubic feet of gas and air at the different temperatures is shown. For each degree there is a change of 0.002056 in volume.

TABLE 13.—*Change in volume of 1,000 feet of air or natural gas, owing to change in temperature.*[a]

Temperature.	Volume of 1,000 cubic feet of gas measured at temperatures other then 60° F.	Loss or gain in volume.	Specific gravity (specific gravity= 0.6 at 60° F.).	Weight of 1,000 cubic feet of gas (0.6 specific gravity at 60° F.).	Weight of 1,000 cubic feet of air.
° F.	*Cubic feet.*	*Per cent.*		*Pounds.*	*Pounds.*
0	877	−12.3	0.6841	58.82	85.97
10	897	−10.3	0.6689	56.41	84.33
20	918	− 8.2	0.6536	54.04	82.69
32	943	− 5.7	0.6362	51.36	80.73
40	959	− 4.1	0.6256	49.68	79.43
50	980	− 2.0	0.6124	47.63	77.77
60	1,000	0.0	0.6000	45.67	76.12
70	1,020	+ 2.0	0.5879	43.78	74.48
80	1,041	+ 4.1	0.5763	41.96	72.83
90	1,061	+ 6.1	0.5652	40.23	71.10
100	1,082	+ 8.2	0.5545	38.56	69.55
110	1,102	+10.2	0.5442	36.95	67.90
120	1,122	+12.3	0.5343	35.40	66.26
130	1,143	+14.3	0.5247	34.10	54.62
140	1,163	+16.3	0.5157	32.47	62.98
150	1,184	+18.4	0.5067	31.07	61.33
160	1,204	+20.4	0.4981	29.72	59.69
170	1,225	+22.5	0.4898	28.42	58.05
180	1,245	+24.5	0.4818	27.17	56.40
190	1,265	+26.6	0.4739	25.94	54.76
200	1,285	+28.6	0.4665	24.78	53.12
210	1,306	+30.7	0.4591	23.63	51.48
212	1,311	+31.1	0.4576	23.41	51.16

[a] Westcott, H. P., Handbook of natural gas, Erie, Pa., 1913, p. 379.

SPECIFIC GRAVITY AND BAUMÉ SCALE COMPARED.

Table 14 shows Baumé hydrometer readings from 10° to 90° B. with corresponding specific gravity, and also the corresponding weight of gasoline in pounds per United States gallon at 60° F.

TABLE 14.—*Baumé scale and specific gravity equivalents.*[a]

° B.	Specific gravity.	Pounds in gallon.	° B.	Specific gravity.	Pounds in gallon.	° B.	Specific gravity.	Pounds in gallon.
10	1.000	8.33	37	0.8383	6.99	64	0.7216	6.01
11	0.9929	8.27	38	0.8333	6.94	65	0.7179	5.98
12	0.9859	8.21	39	0.8284	6.90	66	0.7143	5.96
13	0.9790	8.15	40	0.8235	6.86	67	0.7107	5.92
14	0.9722	8.10	41	0.8187	6.82	68	0.7071	5.89
15	0.9655	8.04	42	0.8140	6.78	69	0.7035	5.86
16	0.9589	7.99	43	0.8092	6.74	70	0.7000	5.83
17	0.9524	7.93	44	0.8046	6.70	71	0.6965	5.80
18	0.9459	7.88	45	0.8000	6.66	72	0.6931	5.77
19	0.9396	7.83	46	0.7955	6.62	73	0.6897	5.74
20	0.9333	7.77	47	0.7910	6.59	74	0.6863	5.71
21	0.9272	7.72	48	0.7865	6.55	75	0.6829	5.69
22	0.9211	7.67	49	0.7821	6.51	76	0.6796	5.66
23	0.9150	7.62	50	0.7778	6.48	77	0.6763	5.63
24	0.9091	7.57	51	0.7735	6.44	78	0.6731	5.60
25	0.9032	7.52	52	0.7692	6.40	79	0.6699	5.58
26	0.8974	7.47	53	0.7650	6.37	80	0.6677	5.55
27	0.8917	7.42	54	0.7609	6.33	81	0.6635	5.52
28	0.8861	7.38	55	0.7568	6.30	82	0.6604	5.50
29	0.8805	7.33	56	0.7527	6.27	83	0.6573	5.47
30	0.8750	7.29	57	0.7487	6.23	84	0.6542	5.45
31	0.8696	7.24	58	0.7447	6.20	85	0.6512	5.42
32	0.8642	7.20	59	0.7407	6.17	86	0.6482	5.40
33	0.8589	7.15	60	0.7368	6.13	87	0.6452	5.37
34	0.8537	7.11	61	0.7330	6.10	88	0.6422	5.35
35	0.8485	7.07	62	0.7292	6.07	89	0.6393	5.32
36	0.8434	7.02	63	0.7254	6.04	90	0.6364	5.30

[a] U. S. Bureau of Standards, United States standard tables for petroleum oils, Circular 57, 1916, p. 57.

NOTE.—Degrees Baumé may be converted to specific gravity by adding 130 to the number of degrees Baumé and dividing the sum by 140.

CAPACITIES OF ORIFICES.

Table 15 shows the capacities of orifices, for testing small flows of natural gas, ranging from one-eighth of an inch to $1\frac{1}{4}$ inches in diameter in plates one-eighth of an inch thick.

TABLE 15.—*Capacities of orifices for testing flows of natural gas from small gas wells and casing-head gas from oil wells.* [a]

[Temperature, 60° F.; atmospheric pressure, 14.4 pounds per square inch.]

THREE-EIGHTHS-INCH ORIFICE IN PLATE ONE-EIGHTH INCH THICK.

Pressure.	Capacity, in cubic feet per 24 hours, at specific gravity of—																	
	0.6	0.65	0.7	0.75	0.8	0.85	0.9	0.95	1	1.05	1.10	1.15	1.20	1.30	1.40	1.50	1.60	1.70
Inches of water.																		
0.5	2,270	2,180	2,100	2,030	1,970	1,910	1,850	1,810	1,760	1,720	1,680	1,640	1,610	1,540	1,490	1,440	1,390	1,350
1.0	3,460	3,320	3,200	3,090	3,000	2,910	2,820	2,750	2,680	2,620	2,550	2,500	2,450	2,350	2,260	2,190	2,120	2,050
1.5	4,310	4,140	3,990	3,860	3,730	3,620	3,520	3,420	3,339	3,260	3,180	3,110	3,050	2,930	2,820	2,730	2,640	2,560
2.0	4,830	4,640	4,470	4,320	4,180	4,060	3,940	3,840	3,740	3,650	3,560	3,490	3,410	3,280	3,160	3,050	2,960	2,870
2.5	5,400	5,190	5,000	4,830	4,680	4,540	4,410	4,290	4,186	4,080	3,990	3,900	3,820	3,670	3,540	3,420	3,310	3,210
3.0	5,770	5,550	5,350	5,170	5,000	4,850	4,720	4,590	4,474	4,370	4,260	4,170	4,080	3,920	3,780	3,650	3,540	3,430
3.5	6,290	6,050	5,830	5,630	5,450	5,290	5,140	5,000	4,875	4,760	4,650	4,550	4,450	4,270	4,120	3,980	3,850	3,740
4.0	6,650	6,390	6,160	5,950	5,760	5,590	5,430	5,280	5,152	5,030	4,910	4,800	4,700	4,520	4,350	4,210	4,070	3,950
4.5	7,210	6,930	6,680	6,450	6,240	6,060	5,890	5,730	5,585	5,450	5,330	5,210	5,100	4,900	4,720	4,560	4,410	4,280
5.0	7,680	7,380	7,110	6,870	6,650	6,450	6,270	6,100	5,946	5,800	5,670	5,540	5,430	5,210	5,020	4,850	4,700	4,560
5.5	8,100	7,790	7,500	7,250	7,020	6,810	6,620	6,440	6,278	6.130	5,980	5,850	5,730	5,510	5,310	5,130	4,960	4,810
6.0	8,290	7,970	7,680	7,420	7,180	6,970	6,770	6,590	6,423	6,270	6,120	5,990	5,860	5,630	5,430	5,240	5,080	4,930

ONE-HALF-INCH ORIFICE IN PLATE ONE-EIGHTH INCH THICK.

Pressure.	0.6	0.65	0.7	0.75	0.8	0.85	0.9	0.95	1	1.05	1.10	1.15	1.20	1.30	1.40	1.50	1.60	1.70
0.5	4,490	4,320	4,160	4.020	3,890	3,770	3,670	3,570	3,480	3,400	3,320	3,250	3,180	3,050	2,940	2,840	2,750	2,670
1.0	6,260	6,010	5,790	5,600	5,440	5,260	5,110	4,970	4,850	4,730	4,620	4,520	4,420	4,250	4,100	3,960	3,830	3,720
1.5	7,900	7,590	7,310	7,070	6,840	6,640	6,450	6,280	6,120	5,970	5,830	5,710	5,590	5,370	5,170	5,000	4,840	4,690
2.0	9,140	8,780	8,460	8,170	7,910	7,680	7,460	7,260	7,080	6,910	6,750	6,600	6,460	6,210	5,980	5,780	5,600	5,430
2.5	10,220	9,820	9,470	9,140	8,850	8,590	8,350	8,120	7,920	7,730	7,550	7,380	7,230	6,950	6,690	6,470	6,260	6,070
3.0	11,150	10,720	10,330	9,980	9,660	9,370	9,110	8,860	8,640	8,430	8,240	8,060	7,890	7,580	7,300	7,050	6,830	6,630
3.5	12,020	11,550	11,130	10,750	10,410	10.100	9,810	9,550	9,310	9,090	8,880	8,680	8,500	8,170	7,870	7,600	7,361	7,140
4.0	12,800	12,290	11,850	11,440	11,080	10,750	10,450	10,170	9,910	9,670	9,450	9,240	9,050	8,690	8,380	8,090	7,840	7,600
4.5	13,480	12,950	12,480	12,050	11,670	11,320	11,000	10,710	10,440	10,190	9,950	9,730	9,530	9,160	8,820	8,520	8,250	8,010
5.0	14,130	13,570	13,080	12,640	12,230	11,870	11,530	11,230	10,940	10,680	10,430	10,200	9,990	9,600	9,250	8,930	8,650	8,390
5.5	14,690	14,110	13,600	13,130	12,720	12,340	11,990	11,670	11,380	11,100	10,850	10,610	10,380	9,980	9,610	9,290	8,990	8,720
6.0	15,210	14,620	14,080	13,610	13,170	12,780	12,420	12,090	11,780	11,500	11,230	10,990	10,760	10,330	9,960	9,620	9,310	9,040

a Wescott, H. P., Handbook of casing-head gas, 1916, pp. 56–62.

TABLE 15.—*Capacities of orifices for testing flows of natural gas from small gas wells and casing-head gas from oil wells*—Continued.

THREE-FOURTHS-INCH ORIFICE IN PLATE ONE-EIGHTH INCH THICK.

Pressure.	Capacity, in cubic feet per 24 hours, at specific gravity of—																
	0.6	0.65	0.7	0.75	0.8	0.85	0.9	0.95	1	1.05	1.10	1.15	1.20	1.30	1.40	1.50	1.60	1.70
Inches of water.																		
0.5	10,560	10,150	9,780	9,450	9,150	8,880	8,630	8,400	8,180	7,990	7,800	7,630	7,470	7,170	6,920	6,680	6,470	6,280
1.0	14,530	13,960	13,450	13,000	12,580	12,210	11,860	11,550	11,260	10,980	10,730	10,500	10,280	9,870	9,510	9,190	8,900	8,630
1.5	17,720	17,030	16,410	15,850	15,350	14,890	14,470	14,080	13,730	13,400	13,090	12,800	12,530	12,040	11,600	11,210	10,850	10,530
2.0	20.390	19,590	18,870	18,230	17,650	17,130	16,650	16,200	15,790	15,410	15,060	14,730	14,420	13,850	13,350	12,890	12,480	12,110
2.5	22,740	21,850	21,050	20,340	19,700	19,110	18,570	18,070	17,620	17,190	16,800	16,430	16,080	15,450	14,890	14,380	13,930	13,510
3.0	24,880	23,900	23,030	22,250	21,550	20,900	20,310	19,770	19,270	18,810	18,380	17,970	17,590	16,900	16,290	15,730	15,230	14,780
3.5	26,990	25,930	24,980	24,140	23,370	22,670	22,030	21,450	20,900	20,400	19,930	19,490	19,080	18.330	17,670	17,070	16,530	16,030
4.0	28.970	27,830	26,820	25,910	25,090	24,340	23,650	23,020	22,440	21,900	21,400	20,920	20,480	19,680	18.960	18,320	17,740	17,210
4.5	30,800	29,590	28,510	27,550	26,670	25,870	25,150	24,470	23,860	23,280	22,750	22,250	21,770	20,920	20,160	19,480	18,860	18,300
5.0	32,500	31,230	30,090	29,070	28,150	27,210	26,540	25,830	25,180	24,570	24,000	23,580	22,980	22,080	21,280	20,550	19,900	19,310
5.5	34,080	32,740	31,530	30,480	29,510	28,630	27,830	27,080	26,400	25,760	25,170	24,620	24,100	23,150	22,310	21,550	20,870	20,250
6.0	35,630	34,230	32,990	31,870	30,860	29,940	29,090	28,320	27,600	26,930	26,310	25,740	25,200	24,200	23,330	22,530	21,820	21,170

1-INCH ORIFICE IN PLATE ONE-EIGHTH INCH THICK.

Pressure.	0.6	0.65	0.7	0.75	0.8	0.85	0.9	0.95	1	1.05	1.10	1.15	1.20	1.30	1.40	1.50	1.60	1.70
1	26,440	25,440	24,500	23,660	22,920	22,220	21,600	21,020	20,520	20,010	19,560	19,120	18,720	18,000	17,320	16,750	16,200	15,720
2	37,510	36,040	34,750	33,600	32,520	31,530	30,640	29,800	29,080	28,360	27,720	27,120	26,540	25,480	24,570	23,760	22,990	22,290
3	46,440	44,640	43,000	41,540	40,240	39,020	37,940	36,880	36,000	35,130	34,320	33,550	32,850	31,560	30,400	29,370	28,440	27,600
4	52,630	50,590	48,740	47,060	45,600	44,200	42,980	41,800	40,800	39,790	38,880	38,010	37,220	35,760	34,460	33,310	32,230	31,270
5	57,880	55,630	53,610	51,790	50,160	48,640	47,280	45,980	44,880	43,770	42,760	41,830	40,940	39,360	37,920	36,620	35,470	34,410
6	63,140	60,720	58,480	56,490	54,720	53,060	51,600	50,180	48,960	47,760	46,650	45,640	44,680	42,960	41,370	39,960	38,680	37,530
7	68,110	65,470	63,090	60,910	59,040	57,210	55,630	54,120	52,800	51,500	50,320	49,220	48,190	46,320	44,610	43,100	41,730	40,480
8	73,050	70,220	67,680	65,350	63,310	61,390	59,680	58,050	56,640	55,240	54,000	52,800	51,690	49,680	47,850	46,220	44,760	43,410
9	77,680	74,680	72,000	69,500	67,340	65,280	63,480	61,720	60,240	58,800	57,430	56,160	54,960	52,800	50,880	49,170	47,610	46,200
10	82,340	79,150	76,270	73,650	71,370	69,190	67,270	65,420	63,840	62,280	60,860	59,520	58,240	55,960	53,920	52,100	50,440	48,960
11	86,680	83,320	80,300	77,540	75,120	72,840	70,800	68,880	67,200	65,560	64,080	62,660	61,320	58,920	56,780	54,860	53,110	51,520
12	90,720	87,190	84,000	81,140	78,600	76,220	74,110	72,000	70,320	68,610	67,030	65,560	64,170	61,680	59,400	57,400	55,580	53,920

Inches of mercury.																		
0.5	67,200	64,600	62,300	60,100	58,200	56,500	54,900	53,400	52,100	50,800	49,600	48,600	47,500	45,700	44,000	42,500	41,100	39,900
1.0	95,200	91,500	88,200	85,100	82,500	80,000	77,800	75,600	73,800	72,800	70,300	68,800	67,300	64,700	62,300	60,200	58,300	56,600
1.5	116,600	112,000	108,000	101,300	101,000	97,900	95,300	92,600	90,400	88,200	86,200	84,300	82,500	79,200	76,300	73,800	71,400	69,300
2.0	134,600	129,400	124,700	120,400	116,700	113,100	110,000	107,000	104,400	101,800	99,500	97,300	95,300	91,500	88,200	85,200	82,500	80,000
2.5	145,600	139,900	134,900	130,200	126,200	122,400	118,900	115,700	112,900	110,100	107,600	105,300	103,000	99,000	95,400	92,200	89,200	86,500
3.0	164,900	158,500	152,700	147,500	142,900	138,600	134,700	131,000	127,800	124,700	121,800	119,200	116,600	112,000	108,000	104,300	101,000	98,000
3.5	178,200	171,300	165,100	159,400	151,500	149,800	145,600	141,600	138,200	134,800	131,700	128,800	126,100	121,200	116,700	112,800	109,200	105,900
4.0	190,400	183,000	176,400	170,300	165,000	160,000	155,600	151,300	147,600	144,000	140,700	137,600	134,700	129,400	124,700	120,500	116,600	113,200
5.0	212,900	204,600	197,200	190,400	184,500	178,900	174,000	169,200	165,000	161,000	157,300	153,900	150,600	144,700	139,400	134,700	130,400	126,500
6.0	233,200	224,100	216,000	208,600	202,100	195,900	190,500	185,300	180,800	176,400	172,300	168,600	165,000	158,500	152,700	147,600	142,900	138,600
7.0	251,900	242,100	233,400	225,300	218,300	211,700	205,800	200,200	195,300	190,600	186,200	182,100	178,200	171,200	165,000	159,400	154,300	149,700
8.0	269,400	258,900	249,500	240,900	233,400	226,400	220,100	214,000	208,800	203,700	199,100	194,700	190,600	183,100	176,400	170,500	165,000	160,100
9.0	285,700	274,600	264,700	255,600	247,600	240,100	233,500	227,000	221,500	216,100	211,200	206,500	202,100	194,200	187,100	180,800	175,000	169,800
10.0	301,200	289,500	279,000	269,400	261,000	253,100	246,100	239,300	233,500	227,800	222,600	217,700	213,100	204,700	197,300	190,600	184,500	179,000
11.0	315,800	303,600	292,500	282,500	273,700	265,400	258,000	250,900	244,800	238,900	233,400	228,300	223,400	214,700	206,800	199,900	193,500	187,700
12.0	328,400	315,700	304,200	293,800	284,600	276,000	268,400	261,000	254,600	248,400	242,700	237,400	232,400	223,300	215,100	207,900	201,200	195,200

1¼-INCH ORIFICE IN PLATE ONE-EIGHTH INCH THICK.

Inches of water.																		
0.5	32,780	31,490	30,350	29,320	28,390	27,540	26,760	26,050	25,390	24,779	24,210	23,680	23,180	22,270	21,458	20,730	20,070	19,470
1.0	46,260	44,440	42,830	41,380	40,060	38,860	37,770	36,760	35,830	34,968	34,160	33,410	32,710	31,420	30,280	29,250	28,320	27,480
1.5	56,600	54,380	52,410	50,630	49,020	47,560	46,210	44,980	43,850	42,790	41,810	40,890	40,030	38.460	37,060	35,800	34,670	33,630
2.0	64,840	62,300	60,040	58,000	56,160	54,480	52,940	51,530	50,230	49,020	47,890	46,840	45,850	44,050	42,450	41,010	39,710	38,520
2.5	72,400	69,570	67,040	64,760	62,710	60,830	59,120	57,540	56,090	54,735	53,480	52,300	51,200	49,190	47,400	45,800	44,340	43,020
3.0	77,980	74,920	72,200	69,750	67,540	65,520	63,670	61,970	60,410	58,950	57,600	56,330	55,150	52,980	51,050	49,320	47,760	46,330
3.5	84,490	81,180	78,220	75,570	73,170	70,980	68,980	67,140	65,450	63,870	62,400	61,030	59,750	57,400	55,310	53,440	51,740	50,200
4.0	91,400	87,810	84,620	81,750	79,150	76,790	74,620	72,630	70,800	69,090	67,500	66,020	64,630	62,090	59,840	57,810	55,970	54,300
4.5	97,810	93,980	90,560	87,490	84,710	82,180	79,860	77,730	75,770	73,940	72,240	70,650	69,170	66,450	64,040	61,860	59,900	58,110
5.0	103,260	99,210	95,610	92,370	89,430	86,760	84,310	82,060	80,000	78,070	76,280	74,600	73,030	70,160	67,610	65,320	63,240	61,360
5.5	107,230	103,020	99,280	95,910	92,870	90,090	87,550	85,210	83,060	81,060	79,194	77,450	75,820	72,850	70,200	67,820	65,660	63,700

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INDEX.

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